STATE OF CONNECTICUT

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

DOCKET NO. 14-05-06 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

December 17, 2014

By the following Commissioners:

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<u>DECISION</u>

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FINAL DECISION

I. INTRODUCTION

A. SUMMARY

In this Decision, the Public Utilities Regulatory Authority reviews The Connecticut Light and Power Company's request for a rate increase pursuant to an Application filed on June 9, 2014 requesting an increase in revenue of $231.582 million and a 10.2% return on equity. On September 22, 2014 the request was revised to an increase in revenue of $221.098 million. The Public Utilities Regulatory Authority approves an increase in revenue of $134.076 million[1] and a base return on equity of 9.17%. This is an increase of 13.9% to distribution rates and approximately 3.3% to total rates.

In granting the revenue increases, the Public Utilities Regulatory Authority allows The Connecticut Light and Power 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 made in this Decision, will result in just and reasonable rates. It will provide The Connecticut Light and Power 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 Connecticut Light and Power 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 1.2 million customers in Connecticut. In addition, it must provide satisfactory customer service and provide a fair return to its investors.

The Public Utilities Regulatory Authority rejects The Connecticut Light and Power Company's request for an allowed return on equity of 10.2% and has determined that an allowed base return on equity of 9.17% is fair and reasonable. In regulating CL&P to allow a return commensurate with the current economic conditions, the Authority has determined that investors expect less of a return today than in 2010, when the return was established at 9.40%. The base allowed return on equity has been decreased by 15 basis points to 9.02% for a period of one year to reflect a penalty for The Connecticut Light and Power Company's poor performance in preparing for and restoring service from Tropical Storm Irene in 2011 and the major snowstorm that occurred in late October, 2011.

This Decision approves the proposed level of $257 million in capital spending, finding that this level of spending is necessary for safety, reliability and maintenance of the franchise. This Decision also includes past system resiliency spending in rates, which is expected to reduce the severity and frequency of outages to customers in

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[1] As discussed below, the Public Utilities Regulatory Authority finds a one year return on equity penalty of 15 basis points appropriate. This penalty reduces the initial revenue increase to $129.679 million.

future weather related events, and authorizes the initiation of new resiliency programs, subject to Public Utility Regulatory Authority review and approval of spending levels in a future proceeding. Further, this Decision includes in rates the costs incurred by The Connecticut Light and Power Company in preparing for and restoring service from major storms in 2011 and 2012, as determined in previous proceedings. This Decision also approves funding for an expanded troubleshooter organization, which is expected to reduce the duration of outages at nights and on weekends.

Major reductions to revenue requirements requested by The Connecticut Light and Power Company include reductions in the requested return on equity, cash working capital of $1.869 million, $7.44 million in the requested level of depreciation expense, and $22 million in operations and maintenance expenses.

The Authority approves certain changes to The Connecticut Light and Power Company's rates and revenues. This Decision makes certain adjustments to pole attachment revenue. The Decision accepts the Company's proposed sales forecast and revenue allocation methodology as reasonable for setting rates. The Decision lowers the proposed increases in fixed charges proposed for the residential and small commercial rates. The Street Lighting rates have been unbundled into system and equipment components and the proposed LED lighting options are approved. The Authority recalculates the Company's pole attachment rates as outlined herein. This Decision also approves a revenue decoupling mechanism as outlined herein. The approved revenue requirements, revenue allocation and rate design changes discussed above will result in an increase of approximately $7.12 per month for the average residential customer bill.

B. BACKGROUND OF PROCEEDING

The Connecticut Light and Power Company (CL&P or Company) is a public service company within the meaning of §16-1 of the General Statutes of Connecticut (Conn. Gen. Stat.). CL&P is a subsidiary of Northeast Utilities (NU). The Company currently provides electric service in 149 towns and cities in Connecticut. Application, p. 3.

By letter dated May 9, 2014, CL&P provided notice of its intention to file an application for approval to amend its rate schedules (Application) 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). In addition, the Company requested waiver of certain provisions of the Standard Filing Requirements (SFRs).

By letter dated May 20, 2014, the Authority granted the Company's request for waiver of certain portions of the SFRs for Large Public Utility Companies. The Authority also approved the Company's request for allowance to submit data required in Schedules F-1.0 through F-9.0 on a calendar year basis reflecting the 12-month period ending December 31, 2013.

By Application dated June 9, 2014, CL&P 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. The Company indicated that this increase is necessary to address a distribution operating deficiency of $116.7 million, and to implement recovery of $89.5 million of storm costs and $25.3 million of system resiliency costs approved by the Authority in prior dockets.[2] In total, the Company proposed rates designed to recover additional costs of $221.098 million during the period from December 1, 2014 - November 30, 2015 (Rate Year). Application, pp. 2 and 3.

C. CONDUCT OF PROCEEDING

On June 3, 2014, pursuant to Conn. Gen. Stat. §16-19(a), the PURA notified all admitted parties and intervenors that it would extend the 150-day period, directed by Conn. Gen. Stat. §16-19(a), to render a final Decision in this docket by 30 additional days.

By Notice of Audit dated June 13, 2014, the Authority conducted an audit of CL&P's books and records at the Company's offices located at 107 Selden Street, Berlin, Connecticut, 06037, beginning on June 23, 2014. The Authority conducted a separate audit of the Company's rates and revenues at the same location on July 10, 2014, pursuant to a Notice of Audit dated July 2, 2014.

Pursuant to a Notice of Pre-Hearing Conference dated June 3, 2014, the Authority conducted a Pre-Hearing Conference on June 19, 2014, to discuss procedural issues with all admitted parties and intervenors, at the Authority's offices located at Ten Franklin Square, New Britain, CT, 06051. At the Prehearing Conference, the Authority and all Parties agreed that the schedule would be extended to provide for a Final Decision by December 17, 2014, with rates to go into effect on December 1, 2014.

By Notice of Hearing dated July 21, 2014, pursuant to Conn. Gen. Stat. §§16-11, 16-19 and 16-19e, the Authority conducted daytime hearing sessions at its offices on August 27 and 28, 2014 and September 2, 3, 4, 5, 8, 9, 10, 11 and 12, 2014. The hearings were continued to September 24 and 25, 2014.

In addition, the Authority held evening sessions solely for the purpose of receiving public comments. The hearings commenced at 6:30 p.m. on the following dates, at the following locations: August 27, 2014, at the Authority's offices; August 28, 2014, at the Stamford Government Center, 888 Washington Boulevard, Stamford, Connecticut; and September 3, 2014, at New London City Hall, 181 State Street, New London, Connecticut.

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[2] In the Decision dated March 12, 2014 in Docket No. 13-03-23, Petition of The Connecticut Light and Power Company for Approval to Recover Its 2011-2012 Major Storm Costs, the Authority approved cost recovery of certain major storm related costs. In its Decision dated January 16, 2013 in Docket No. 12-07-06, Application of The Connecticut Light and Power Company for Approval of Its System Resiliency Plan (Resiliency Decision), the Authority approved cost recovery of costs related to system resiliency initiatives.

The Authority issued its Proposed Final Decision in this matter on December 1, 2014. 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 Connecticut Light and Power Company, 107 Selden Street, Berlin, Connecticut 06037; Office of Consumer Counsel, Ten Franklin Square, New Britain, Connecticut 06051; and Department of Energy and Environmental Protection Commissioner Robert F. Klee, 79 Elm Street, Hartford, CT 06106-5127 as Parties to this proceeding.

Intervenor status was granted to: Office of the Attorney General; Environment Northeast; Cablevision of Connecticut, LP; International Brotherhood of Electrical Workers; New England Cable and Telecommunications Association, Inc.; Fiber Technology Networks, LLC; and Wal-Mart Stores, Inc.

E. PUBLIC COMMENT

The Authority conducted evening public comment hearings within the CL&P service territory for the purpose of receiving comments from the general public concerning the Application. CL&P's notice to customers regarding the hearings, submitted by the Company on June 16, 2014, was approved by the Authority on June 17, 2014.

A total of 203 persons attended the public comment hearings and 64 of those persons provided testimony to the Authority. U.S. Senator Richard Blumenthal urged the Authority to consider how a 59% increase in the residential customer service charge would affect the poor and elderly. Tr. 8/27/14, pp. 251-253. State Representative Lonnie Reed stated that CL&P'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. 254-257.

Public comments mirrored those provided by the public officials. Residential customers were particularly opposed to the proposed $9.50 increase in the customer service charge. Tr. 8/27/14, pp. 263-265, pp. 269-277 and pp. 284-291; Tr. 8/28/14, pp. 563-565 and pp. 582-591; Tr. 9/3/14, pp. 1099-1118 and pp. 1134-1138. Overall, most Connecticut residents and businesses that spoke or submitted written comment were not supportive of CL&P's Application. Many cited the state's current economic condition and the financial impact of a rate increase.

Several organizations spoke in favor of CL&P's Application, stating that reliability of electric service was very important. The Windham Region Chamber of Commerce noted improvements in CL&P's quality of communications and coordination of staff and technology than it had presented before the last rate case. Tr. 9/3/14, pp. 1094-1098.

The Authority also received approximately 2,000 letters and emails regarding the Application. There were approximately 25 letters in support of the Application; however, nearly all of the persons who wrote opposed CL&P's rate increase request, stating reasons similar to those offered at the evening public hearings.

II. AUTHORITY ANALYSIS

A. Test Year / Rate Year

It is the practice of the Authority in utility rate cases to establish rates prospectively upon review of a historical Test Year. Revenues and certain expenses were adjusted for known changes or to reflect a normalized, annualized test year, known as the pro forma test year. In this case, the Company used the operating results for the 12 months ending December 31, 2013, as its Test Year. Schedule A-1.0. The Authority, with these adjustments, accepts this time period as the Test Year. The Rate Year is the period from December 1, 2014 to November 30, 2015, as proposed by the Company.

B. Rate Base

1. Capital Expenditures

CL&P's proposed capital expenditures for the Rate Year are as follows:

Table 1

Proposed Capital Program

Year	Category of Capital Expenditure	Amount (in millions)	Rate Component for Recovery in 2015
2015	Traditional Capital Program	$257	Distribution Rate
2015	Pre-Approved System Resiliency Plan	$52	Distribution Rate
2015	New System Resiliency Programs	$44	NBFMCC
Total		**$353**	

Bowes PFT, p. 11.

The Traditional Capital Program consists of expenditures for programs that address routine infrastructure issues such as those necessary to supply new customer load, meet peak loads, meet basic business requirements, meet regulatory commitments, and reliability related projects. The Pre-Approved System Resiliency Plan consists of system resiliency expenditures for programs that were approved in the Resiliency Decision, and whose recovery was allowed through the Non-Bypassable Federally Mandated Congestion Charge (NBFMCC) until the following rate proceeding. The New System Resiliency Programs are system resiliency expenditures for programs that were not approved in the Resiliency Decision, which the Company contended would have a long-term impact on customer reliability. The New System Resiliency Programs expenditures would not be included in rates. Rather, the Company requested that the Authority authorize them subject to a future reopening of Docket No. 12-07-06 to review their costs and authorize recovery through the NBFMCC.

a. Traditional Capital Program

CL&P stated that it proposed to spend $257 million on its Traditional Capital Program in the Rate Year, and noted that it spent $268 million for the same types of programs in 2013. At the requested level of spending, the Company expects to be able to improve day-to-day reliability while decreasing capital spending due to the combined effect of the following three factors: 1) efficiencies achieved through reorganization and consolidation initiatives; 2) improvements achieved as a byproduct of system resiliency programs; and 3) implementation of the new troubleshooter organization. Bowes PFT, pp. 11 and 12.

CL&P's Traditional Capital Program, disaggregated by focus area, is shown in the table below.

Table 2

CL&P Capital Program 2013-2015
($ in Millions)

Focus Area	Description	2013 Actual	2014 Forecast	2015 Forecast
New Customer	Customer-driven projects	48.6	38.5	40.5
Peak Capacity	Distribution/substation capacity projects	24.4	22.3	21.1
Basic Business	Equipment failures/facilities/IT/vehicles/ environmental/lighting/miscellaneous	106.5	109.8	114.9
Regulatory	Grounding/double poles/high-over-low voltage/cable replacement/worst circuits	25.5	20.1	12.0
Reliability	Enhanced trimming/distribution line reliability/substation reliability/network reliability	66.7	65	68.2

Response to Interrogatory EN-2.

No party or intervenor opposed any Traditional Capital Program specific capital expenditure or project to be added to plant-in-service.

The OCC stated that data provided by CL&P shows that actual plant additions during the years 2008 through 2013 were 4.21% lower than budgeted. According to the OCC, forecasted plant additions should be reduced by this amount to determine the appropriate level to be included in rates. The OCC also criticized CL&P for providing a forecast for plant-in-service but basing its analyses on capital expenditures. Finally, the OCC questioned whether the Company's Board of Directors authorized the expenditures, and asserted that unsuccessful efforts to compel CL&P to produce a capital expenditure approval policy casts doubt on the Company's capital plans. OCC Brief, pp. 39-44.

CL&P stated that capital expenditures do not equate to plant-in-service due to timing differences. For example, large multi-year projects involve capital expenditures each year, but are not included in plant-in-service until the projects are complete. Furthermore, during the period 2008-2013, CL&P spent the capital expenditures forecasted in prior rate cases. Finally, CL&P observed that the OCC selectively included 2008 and 2009 in its comparative analysis, when the variances were abnormally large due to the unforeseen severe global recession, which reduced capital deployment. When those years are removed, plant-in-service was 99.86% of the Company's budgeted level, or almost precisely equal to forecast. CL&P Joint Rebuttal Testimony of Kenneth Bowes and Jeffrey Michelson, pp. 4-7.

The Authority examined the issue of plant-in-service forecasting for the purpose of adjustments to rate base in its Decision dated February 4, 2006 in Docket No. 05-06-04, Application of The United Illuminating Company to Increase Its Rates and Charges (UI Decision). In that Decision, the Authority found as follows:

> The Department believes construction programs should be analyzed by examining the needs the programs are intended to address, and the reasonableness of the solutions to those needs. Comparisons to historicals are useful to assist in determining whether the total expenditures are within a range of reasonableness, but even if projected expenditures vastly exceed historicals, to rationally analyze a company's proposed expenditures the Department must analyze them on a project-specific basis. Therefore, any adjustments based on gross comparisons to historical levels alone are not sufficient. Regarding the OCC's assertion that projected plant additions are much higher than historical, the Department notes that the plant additions are netted against retirements. Because additions can vary largely from one year to another, and because large amounts of retirements can offset the additions leading to a low net number, it is not valid to compare net plant additions between years… The Department therefore believes that comparisons to historical additions are not a valid determinant of future plant additions.

UI Decision, p. 24.

The Authority reiterates these findings, as the premises have not changed. Although it is appropriate to consider plant additions in forecasting, a plant addition forecast should be based on capital expenditures. The Authority closely examined capital expenditures in this proceeding. Furthermore, in the past several CL&P rate proceedings, the Authority has required the Company to report on capital expenditure variances each year, which allows the PURA to closely monitor spending. Over the three years since CL&P's last rate proceeding in Docket No. 09-12-05, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules (2009 CL&P Rate Case), CL&P's actual and forecasted capital expenditures were as follows.

Table 3

CL&P Capital Expenditures 2010-2012
($ in millions)

	Forecast	Actual
2010	310.8	305.4
2011	332.6	338.5
2012	315.4	312.8

Decision dated June 30, 2010 in Docket No. 09-12-05 (2009 CL&P Rate Case Decision); Order No. 2 Compliance Filings dated March 31, 2011, March 30, 2012 and March 26, 2013.

Total capital spending over the years 2010-2012 was $956.7 million, which is within approximately 0.2% of the 2009 CL&P Rate Case forecast amount of $958.8 million. This historically accurate capital spending forecast gives high confidence to CL&P's planned capital spending presented in this case. Therefore, the Authority will not make any adjustment to CL&P's proposed capital spending/plant-in-service on the basis proposed by the OCC.

The Authority reviewed CL&P's proposed capital program and concludes that the expenditures are reasonable and necessary for safety, reliability, and maintenance of the franchise.

The Company will be required to report on its capital spending as follows: by November 30 of 2015, 2016 and 2017, with a budget/forecast of spending by initiative or category for the following year; and by March 31 of each year 2014, 2015 and 2016 showing actual spending by initiative or category for the preceding year. These reporting requirements recognize that CL&P is required by the NSTAR merger settlement agreement,[3] to apply to the Authority for a rate proceeding in 2017; therefore, the PURA will remain apprised of capital spending and have a history of such spending in its records when the 2017 application is made. The Authority recognizes that plans may change for good reason over the next two 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.

b. Pre-Approved System Resiliency Costs

The Resiliency Decision allowed the Company to flow the costs of the System Resiliency Plan through the NBFMCC until the Company's next rate case, at which time the costs would be factored into the Company revenue requirements. The Authority

[3] Approved by the Authority in its Decision dated April 2, 2013 in Docket No. 12-01-07, Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR (Merger Decision).

finds that the Company has complied with the ratemaking treatment as allowed in the Resiliency Decision in this filing. Resiliency spending, in the amount of $25.343 million, for the years 2013-2014 is added to the Company's rate base and removed from NBFMCC revenue requirements.

The Resiliency Decision allowed forecasted spending through 2017 for resiliency measures. The table below lists amounts for resiliency spending 2014-2017.

Table 4

Year	Estimated Capital	Estimated Expense	Total Spending
2014	45,000	8,000	53,000
2015	52,000	9,000	61,000
2016	68,000	9,000	77,000
2017	68,000	9,000	77,000

Resiliency Decision, p. 6.

If the PURA allows the proposed 2014-2015 resiliency expenditures in revenue requirements, the OCC recommended the Authority should order an audit of the actual costs on an annual basis to determine whether the expenditures made are supported by real cost documentation, and that the costs were prudent and specifically related to system resiliency.

The Authority finds that the orders contained within the Resiliency Decision address the OCC's concerns.

c. Proposed New System Resiliency Costs

CL&P stated that it achieved improvements in service reliability in 2013 primarily through the implementation of best practices and an enhanced vegetation management program. According to the Company, there are other initiatives that are recognized within the industry as having a significant impact on building system resiliency to the long-term benefit of customers. CL&P identified certain core initiatives that, if implemented, would have the greatest long-term impact on system resiliency, and an important secondary impact on system reliability. The Company asserted that these initiatives are necessary to modernize the system and provide its customers with the level of service that they should expect from CL&P. The Company requested authorization to start these programs, subject to a future reopening of Docket No. 12-07-06 to review and approve specific program budgets and to recover the costs of the program through the NBFMCC. None of the new system resiliency costs are included in this case. Bowes PFT, pp. 19 and 20.

CL&P's proposed new resiliency program expenditures in 2015 are as follows.

Table 5

CL&P New Resiliency Programs
($ in Millions)

Program	Description	Proposed Spending ($ millions)
Pole Integrity	Increase resiliency of utility poles	$13
System Automation/ Grid Modernization	Increase system monitoring and control capabilities	$14
Substation Security	Increase physical security of substations	$ 4
Substation Flood Mitigation	Increase the resiliency of selected substations to flood events	$ 2
Infrastructure	Address islanded substations and improve Right of Way lines	$11
Total		$44

Bowes PFT, pp. 19-33.

The OCC stated that the Company is proposing new resiliency spending totaling an additional $368.3 million over the years 2014-2019. This amount more than doubles the $300 million program approved in the Resiliency Decision, and the OCC asserted that that the Authority should wait until after 2017 when more information is known about the efficacy of the existing resiliency program. Furthermore, the OCC objects to using the NBFMCC as a collection method for any new resiliency expenditures; rather, the OCC believed a rate-based collection method should be used. OCC Brief, pp. 149-152.

The Authority shares the OCC's concern regarding the impact of the proposed spending on ratepayers; however, the Company has not requested, nor has the Authority approved, funding levels or cost recovery in this proceeding. The Company only requested Authority permission to proceed with the new resiliency programs, subject to review of proposed spending in an anticipated reopening of Docket No. 12-07-06. Because several of the new resiliency programs address known vulnerabilities in the electric distribution system, the Authority will authorize the program to go forward. However, the Company should be prepared to do so at a level of funding below the levels it is anticipating, subject to the Authority's determination in the reopened Docket No. 12-07-06 proceeding.

The Authority notes that CL&P plans to recover new resiliency spending in the NBFMCC. The NBFMCC was an appropriate vehicle for prior resiliency spending, because the spending was mandated by the NSTAR merger agreement and initiated outside of a rate proceeding. The Authority will allow NBFMCC recovery subject to the budgets approved in the reopened Docket No. 12-07-06 proceeding as a transition until the Company's next rate proceeding. After that time, resiliency spending should be included in rate base. If the Company desires to continue to recover resiliency spending outside of conventional rates, it should seek a legislative solution.

2. Accumulated Deferred Income Taxes

CL&P reported accumulated deferred income taxes (ADITs) of $655.417 million as an offset to rate base for the Test Year, $760.36 million for the proforma period ending December 31, 2014, and $819.14 million for the Rate Year. Schedule B-1.0, p. 2. The Company reported average ADITs of $789.75 million for the Rate Year. Id.

CL&P reported plant related non-FAS 109 ADITs of approximately $461.429 million, $553.453 million, $567.297 million, $674.02 million, and $658.815 million for calendar years ending December 31 in 2009, 2010, 2011, 2012 and 2013, respectively. Response to Interrogatory AC-9, Attachment 1. The Company projected ADITs of $763.758 million and $822.537 million for December 31, 2014 and 2015, respectively. Id. The 2011 ADITs balance was net of deferred taxes of $85.477 million related to the ensued net operation losses (NOL). Otherwise, the ADITs' balance as of December 31, 2011, is $652.774 ($567.297 + $85.477) million. Id. CL&P indicated that ADITs associated with NOL of $3.46 million, $30.46 million and $51.025 million are utilized in 2012, 2013 and 2014, respectively. Id.

The Authority reviewed all exhibits submitted by the Company in this proceeding regarding the average plant related ADITs proposed for the Rate Year. The Authority has several issues with the average ADITs that CL&P used to calculate the average rate base for the Rate Year as discussed below.

a. Repair Tax Deductions

Regarding the repair tax deduction (RTD) proceeding in Docket No. 13-07-06, Joint Petition of George Jepson, Attorney General for the State of Connecticut and Elin Swanson Katz, Consumer Counsel, for an Investigation into the Response of Connecticut's Public Service Companies to Certain Changes to IRS Accounting Regulations (RTD Proceeding), CL&P indicated that this proceeding rather than a generic RTD proceeding is the proper venue to review the regulatory impacts of costs incurred for repair and maintenance of tangible property. Mahoney PFT as Adopted by Michelson, p. 24. Also, the Company stated that the deferred tax liability created by the permanent RTD regulations will reverse over the same time period as the related assets capitalized on its books are depreciated, thereby reversing the deferred tax liability as the remaining book depreciation is realized. The treatment of the RTD is similar to that of any other normalized deduction for tax and regulatory purposes. Id.

In its normalized plant-related ADITs, CL&P included deferred taxes of $40.85 million in 2014 and in 2015. These levels of ADITs are based on RTD allowances of $100 million in each year. Mahoney PFT as Adopted by Michelson, p. 25; Schedules B-7.0 and WPC-3.38, p. 2. CL&P asserted that there are no additional RTD tax benefits in 2012 and 2013 because both years' tax returns showed taxable losses. Mahoney PFT as Adopted by Michelson, p. 25.

In its response to the Authority's request to quantify the RTD amounts available in 2012 and 2013 that were not deducted because of the Company's NOL positions in both years, CL&P stated that any attempt to hypothetically measure the RTD amounts for 2012 or 2013 is meaningless given its NOL positions for these years. Response to

Interrogatory AC-86; Tr. 09/25/14, pp. 2746-2748. The Company stated that its tax planning appropriately seeks to maximize the cash benefits associated with deductions, with minimum risk of audits and disallowances by the Internal Revenue Services (IRS). As a result, the Company did not adopt the RTD temporary regulations and plans to adopt the repairs deduction, using the final regulations in its 2014 tax return. Response to Interrogatory AC-86-SP01, pp. 1 and 2. Simultaneously, CL&P concurred that the benefit associated with potential deductions from 2012 and 2013 will be included in the 2014 adjustment required when its elects to adopt the final RTD regulations. CL&P stated that its 2014 tax returns would include a cumulative RTD adjustment containing amounts that would have been deducted in 2012 and 2013 and that the resulting tax benefits of the method change will be calculated and recorded in its books. Id.

While CL&P reiterated its argument about its NOL positions in 2012 and 2013, it agreed that the benefit associated with prior years, encompassing the amounts that are in question from 2012 and 2013, will be captured as part of a cumulative adjustment deduction in its 2014 tax return. Nevertheless, CL&P argued that the Authority should not make any adjustment to its proposed revenue requirement pertaining to the RTD. The Company asserted that customers are receiving the benefit associated with formal and finalized IRS tax rules and regulations. CL&P Brief, pp. 48 and 49.

The Company's argument is based on the premise that it did not adopt the RTD regulations prior to 2014 because it was in NOL positions in 2012 and 2013 and it would be risky to adopt temporary regulations that not are finalized. The Authority agrees that an earlier adoption of the temporary RTD regulations would have further increased the Company's NOL positions in 2012 and 2013. The Authority's initial inquiry was for CL&P to quantify the RTD amounts available in 2012 and 2013 regardless of whether the amounts were deducted or not. CL&P's response was that based on its tax position or liability it would be meaningless to calculate a hypothetical number for 2012 or 2013, which are tax years prior to the effective date of the finalized RTD regulations. Response to Interrogatory AC-86. Based on its tax strategy, CL&P waited until the RTD regulations were finalized to adopt and avail itself of the benefit of the RTD allowances. Effective with the adoption of the permanent RTD regulations in 2014, there are additional look-back periods for which costs incurred for repair and maintenance of tangible property can be deducted in the 2014 federal income tax return.

The Authority's position is that the Company failed to incorporate the additional deferred tax benefits for the look-back RTD periods, which included 2012 and 2013, in its estimated deferred taxes for 2014. CL&P finally agreed that its 2014 tax return would include a cumulative RTD adjustment for prior periods. CL&P stated that "When the Company adopts the Regulations for its 2014 tax year a cumulative adjustment as a result of the method change will be calculated. Any benefit from the change will be recorded by the Company. Any amounts which would have been deducted in 2012 and 2013 will be included in that cumulative adjustment in the Company's 2014 tax return." Responses to Interrogatories AC-86 and AC-86 SP01; CL&P Brief, p. 48. The Company agreed that 2012 and 2013 RTD allowances to be included in its 2014 cumulative amounts would garner additional normalization deferred tax liabilities that would be recorded on its books. However, the Company only included the deferred taxes associated with RTD allowances in 2014 and 2015 in this proceeding. It failed to include the deferred tax benefits for the 2012 and 2013 RTD expenses that would be included in tax depreciation deductions in its 2014 tax returns as a result of the adoption of the finalized RTD regulations. The question now is what meaningful number would be reflected in the Company's 2014 tax return as the amount representing RTD expenses for the look back periods of 2012 and 2013. The Company initially stated that such figure would be hypothetically meaningless.

The Authority estimated that at a minimum, the total RTD allowances for 2012 and 2013 should be at least 50% of the amount the Company estimated for 2014 and 2015. Thus, the Authority estimated $100 ($100 x 50% x 2) million of RTD for 2012 and 2013. Consequently, the average ADIT amount is increased by $40.85 ($100 x 40.85%) million. Accordingly, the Authority will reduce Company's proposed average rate base by $40.85 million. This amount represents a reasonable amount of tax benefit for the 2012 and 2013 RTD that the Company will include in the total RTD to be deducted in its 2014 tax return.

In its Written Exceptions, CL&P stated that the Authority's determination to reduce its proposed average rate base by $40.85 million for the tax benefit of RTD is a mistake. The Authority made this determination based on the Company's testimony that any RTD amounts that would have been deducted in 2012 and 2013 will be included as part of accumulative RTD amount in its 2014 tax returns. CL&P stated that the Authority confused the principles of its re-computation of its actual tax position in 2012 assuming that the RTD would have been taken with that of the computation of the cumulative "look-back" RTD adjustment allowable under the final IRS regulations in 2014. CL&P Written Exceptions, pp. 23 and 25. According to the Company, the reported $100 million associated with the RTD in 2014 and $100 million in 2015 are not the RTD deductions for each year. The total $200 million represents the cumulative RTD adjustment for all prior years through 2013 and the estimated RTD for 2014. The Company shows the combined amount of $200 million over two years to indicate the cash flow impact of the RTD "catch-up" adjustment in addition to the actual tax accounting impact. Id., p. 26. Furthermore, CL&P stated that the cumulative one-time RTD adjustment for the look-back periods is estimated to be $178 million and that the annual RTD for 2014 is approximately $22 million. Id.

The OCC stated that the Authority's determination related to RTD look-back periods was proper and appropriately recognizes that CL&P will adopt these changes in its 2014 Federal Income Tax return. These tax changes will impact the income taxes paid for 2014 and in the Rate Year as well as ADIT balances. However, the OCC stated that the Authority did not make an adjustment to the Company's Federal income tax expenses. The OCC indicated that, because of CL&P's large annual budgeted capital expenditure associated with infrastructure replacement, a significant portion of the associated infrastructure repair and maintenance costs is likely to qualify as a deduction to its federal tax liability. According to the OCC, in between rate cases, there is the possibility the lower tax expense would increase the Company's earnings. The potential tax refund, increased federal income tax deductions and reduction of income taxes for 2014 and thereafter should be used to reduce the rate increases for the Rate Year in this proceeding. OCC Written Exceptions, pp. 40 and 41. Furthermore, the OCC stated that the RTD adjustment for the look-back periods that is based on only 50% of the Company's estimates for 2014 and 2015 is conservative and would not prevent a windfall to CL&P shareholders when the tax election is made between rate cases. The OCC recommends that, subsequent to CL&P's compliance to Order No. 10 in this Decision, the Authority should have a limited reopener of this proceeding in 2015 to true-up the impact of reduced taxes and tax refunds associated with the new RTD regulations. Id., pp. 41 and 42.

In its Written Exceptions, the AG argued that the RTD adjustment for the look-back period is "extremely conservative" if costs related to system "hardening" for the years subsequent to Tropical Storm Irene, the October 2011 Nor'easter and Super-storm Sandy in October 2012 qualify as RTD investments. AG Written Exceptions, p. 8. Additionally, the AG indicated the actual RTD credits for the look-back periods would not be known until the Company files its 2014 tax returns. The AG suggested that the Authority should hold ratepayers harmless for any errors in RTD estimates and urged the PURA to apply the most reasonable and accurate estimates of the likely qualified RTD amounts. The AG also urged the Authority to assume that the actual qualified investments in years 2012 and 2013 are the same as the $200 million that the Company estimated for 2014 and 2015. The AG further proposed an additional average RTD deferred tax increase of $9.1 million. Finally, the AG suggested that a limited reopening of this proceeding be conducted in September 2015 to reconcile any discrepancies between its estimated RTD credits of $81.7 million and the deferred tax effect of the actual RTD amounts provided in the Company's 2014 Federal income tax return. Id., p. 9.

CL&P testified that "[A]ny amounts which would been deducted in 2012 and 2013 will be included in that cumulative adjustment in the Company's 2014 tax return." Response to Interrogatory AC-86. No information was provided in response to interrogatories, pre-filed testimony or during the hearing to suggest that the reported $100 million RTD in 2014 and $100 million in 2015 represented the total for the look-back-periods and the 2014 annual amounts. The first time CL&P presented this information was in its Written Exceptions. Also, there was no exhibit or testimony in this proceeding that supports the derivations of the total prior periods RTD of $178 million and 2014 annual amount of $22 million that CL&P claimed in its Written Exceptions.

It is important to make the correct determination regarding the appropriate amount of ADIT, including the estimated 2014 RTD amounts, in order to calculate CL&P's allowed rate base. The Authority is concerned withthe discrepancy between the evidence and analysis in the record and CL&P's representations offered in its Written Exceptions. The Authority concludes that it is necessary to reopen this proceeding for the purpose of ensuring that the amount of ADIT is properly calculated. In the reopened proceeding, the Authority will receive evidence on the issue of whether the reported $100 million RTD in 2014 and $100 million in 2015 in total represent the total for the look-back-periods and the 2014 annual amounts. The reopened proceeding will afford all parties and intervenors an opportunity to properly review this new evidence, the potential revenue requirement impact of the new evidence and related issues.

In the meantime, the Company is directed to track and create a regulatory asset for the revenue impact of the RTD adjustment based on its proposal. The Authority will true-up the Company's estimated revenue impact to reflect the proper RTD estimates for 2014 that will be determined in the reopener. Additionally, the Authority will reopen this proceeding for the limited purpose of reconciling the estimated RTD allowed in the initial reopener to the actual amount reported in the Company's 2014 Federal income returns submitted as a compliance filing in this docket.

b. Account 28200 True-Up Adjustments

Unlike other periods with substantial year-over-year increases, the Authority noticed a significant decrease in the ADITs balance in Account 28200 as of December 31, 2013, as compared to the December 31, 2012 balance. The Authority identified and questioned the August 2013 adjustment to reduce the ADITs balance in this account by $124,742,248. Response to Interrogatory AC-128, Attachment 1, Revision 1, p. 33. The Company stated that the August 2013 adjustment, which reduced the deferred tax balance in Account 28200, is related to a true-up adjustment made in its 2012 tax returns and subsequently recorded in its accounting books in August 2013. Late Filed Exhibit Nos. 78 and 79. Specifically, during the course of a year, CL&P books deferred taxes based on a budget projection and such budget projections make certain assumptions. Those assumptions could include any number of different items.

At the end of the year, the Company prepares and files its corporate income tax and then trues up to the corporate income tax at the actual level. The book balance in the 28200 Account at the end of the year should incorporate the actual amount that is reflective of the Company's tax filings. Issues that could cause differences between projected and actual amounts can be anything. CL&P testified that its projected tax deductions for items such as storm activity, bonus depreciation, and repairs may not have occurred for some reason or because some other items on an actual basis precluded them from occurring. So the Company's actual tax return overrules its projections and CL&P corrects to the actual tax return. CL&P averred that it made an adjustment in its 2012 tax return that makes the true-up adjustments to its accounting books necessary. As such, the Company made a $124.742 million reduction to the deferred taxes in August 2013 in Account 28200 which represents a subsequent true-up of estimates that CL&P made during 2012 based on an adjustment in its 2012 tax return. Tr. 09/25/14, pp. 2731-2741.

In its Brief, the Company stated that the amounts in Account 28200 as of December 31, 2012, were estimated based on recognition of transactions related to plant asset retirements, additions and basis adjustments, and the expected deductions under the tax law related to those assets. CL&P stated that its computation of depreciation expense deductions for tax purposes assumed a relatively shorter retirement schedule for certain asset categories. A shorter retirement schedule increases the deduction for depreciation expense for a particular calendar period. In July 2013, when the Company was preparing to file its 2012 federal tax return, it was clear that the combination of actual operating income, increased system investment and the existence of an NOL had eliminated federal tax liability for 2012. There was no federal tax liability to reduce depreciation expense generated by the shorter retirement schedule. Therefore, the Company made a decision to extend the retirement schedule for certain asset categories, which effectively decreased deductions for 2012, and increased depreciation expense for future years. Furthermore, CL&P stated that under IRS tax law, businesses may automatically change from one permissible method of computing depreciation expense for tax purposes to another permissible method upon the filing of a Form 3115. Therefore, the Company submitted a Form 3115 to the IRS, and adjusted the amounts in Account 28200 to match the filed tax return. If the Company had not taken this action, the NOL would have increased and customers would not have realized any tax benefit of the depreciation expense deduction. Also, the change in retirement schedule was made only for tax purposes, which does not require approval by the Authority. Response to Interrogatory AC-97-SP02, pp. 1 and 2; CL&P Brief, pp. 52-54.

The Authority finds that CL&P's August 2013 adjustment to reduce non-FAS 109 ADITs balance in Account 28200 by $124,742,248 is unsupported. The Authority reviewed distribution plant additions and retirements exhibits and determined that actual distribution plant-in-service as of the end of 2008 was approximately $3,757.116 million. Response to Interrogatory OCC-46 Attachment 1, p. 1. The additions and retirements since 2008 are summarized below:

Table 6

Year	Plant Additions (Million)	Retirements (Million)
2009	$256.891	$ 74.479
2010	$287.992	$ 66.550
2011	$287.791	$ 50.040
2012	$324.484	$ 52.149
2013	$289.038	$ 54.455

Response to Interrogatory OCC-46, Attachment 1, p. 1.

Beginning in 2001, several tax law changes allowed corporations special tax deductions, "bonus depreciation" allowances, above the normal Modified Accelerated Cost Recovery System (MACRS) amounts. The levels of recently allowed bonus tax depreciation deductions are summarized below:

Table 7

Periods Covered	Amount (%)
January 1, 2008 through September 8, 2010[4]	50%
September 9, 2010 through December 31, 2011[5]	100%
January 1, 2012 through December 31, 2013[6]	50%

Since 2008, the deferred tax liability amounts resulting from normalization of tax/book differences have grown exponentially for regulated public utilities. Pursuant to the Uniform System of Accounts as codified in Conn. Gen. Stat. §16-2, Account 282 is credited and Account 410 is debited with an amount by which income tax is lower. This is because liberalized depreciations, such as ACRS, MACRS and/or Bonus deductions,

[4] The Economic Stimulus Act of 2008; the Small Business Jobs Act of 2010; and the American Recovery and Reinvestment Act of 2009.
[5] The Tax Relief, Unemployment Compensation Reauthorization, and Job Creation Act of 2010.
[6] Id.; and the American Tax Relief Act of 2012.

are used for income tax purposes, as compared to straight line depreciations for book purposes. Likewise, Account 282 is debited and Account 411 is credited with an amount by which income tax is greater because liberalized depreciations, such as ACRS, MACRS and/or Bonus deductions, are used for income tax purposes in prior years, as compared to straight line depreciations for book purposes. The amount debited to Account 282 and credited to Account 411 represents current income taxes payable due to smaller amounts of tax depreciation currently permitted for property which liberalized tax depreciation was applied in prior years, as compared to regulatory straight-line book depreciation. There is no evidence provided in this proceeding that would suggest that the deferred taxes accrued and recorded in Account 28200 were overstated and above that permissible by current tax laws. The non-FAS 109 ADIT balances in Account 28200 and annual accretion since 2009 are summarized in the table below:

Table 8

Year	Account 28200 Balance (Million)	Net Change (Million)
2009	$422.736	N/A
2010	$510.410	$ 87.674
2011	$606.298	$ 95.888
2012	$706.560	$ 100.262
2013	$664.267	($ 42.293)

Response to Interrogatory AC-128, Attachment 1 Revision 1, pp. 8, 24 and 33.

Also, annual accretions to the ADITs balances in Account 28200, exclusive of true-up adjustments, are summarized below:

Table 9

Year	Annual ADITs Accretions (Million)
2010	$ 81.039
2011	$ 95.888
2012	$101.330
2013	$ 82.449

Id.

The Company's testimony that the $124,742,248 reduction to the deferred taxes recorded in Account 28200 was a subsequent true-up for an adjustment made in the 2012 income tax return is not supported by the information provided in this proceeding. CL&P's assertion that prior years' tax estimates used to calculate the deferred tax balance are being trued-up by the August 2013 $124,742,248 reduction to the balance in Account 28200 belies tax information provided in this proceeding and is improper. The Authority's review of the Company's distribution unit annual balance sheets for the period 2010-2013, showing that the Company made adjustments to the balance in Account 28200 in August of each year as detailed below:

Table 10

Year	Annual August Adjustment to Account 28200
2010	$6.635 million Increase
2011	Zero Adjustment
2012	$1.1 million Decrease
2013	$124.742 million Decrease

Response to Interrogatory AC-128, Attachment 1 Revision 1, pp. 8; 24, 33; and Revision 2 Attachment, p. 33.

As the tables above indicate, the increase to the ADITs balance in 2012 of $101.33 million does not support the recording of over-estimated amounts requiring a subsequent true-up adjustment of approximately $124.742 million in August 2013. Using the Company's current tax composite rate of 40.85%, the total combined federal and state tax depreciation erroneously estimated for 2012 requiring subsequent revision would be approximately $305.4 million ($124,742,248 / 40.85%). This estimate is very conservative because the federal bonus depreciation allowances cannot be claimed for the calculation of Connecticut corporate taxable income. In its federal tax returns, the Company reported tax depreciation deductions of $541,275,640 in 2011 and $586,677,407 in 2012. The distribution portions of the 2011 and 2012 tax depreciation amounts are $359,956,682 and $384,142,472, respectively. Late Filed Exhibit No. 1-PURA AR-13 Attachment.

The increase in the 2012 tax depreciation amount as compared to 2011 does not support overstatement of estimated tax depreciation amounts based on changes to the retirement schedule for certain asset categories. It is more suggestive of an increase to the regulatory deferred liability associated with book/tax timing differences. Additionally, the retirements recorded in the Company's books in 2012 is $52.149 million. This is based on the Company's testimony that the August 2013 reduction to the ADITs balance in Account 28200 was a true-up adjustment related to its proposed changes to its tax retirement schedule. The estimated increase to the total tax depreciation deductions would be approximately $305.4 million in 2012. This would be in addition to the actual total federal tax depreciation deduction of $384,142,472. The Authority estimated that the additional ADITs that would be recorded in the Company's books in Account 28200 in 2012 would be in excess of $200 million to account for CL&P's proposed changes to its tax depreciation schedule, 100% and 50% bonus depreciation deductions for plant additions in 2011 and 2012, respectively, and MACRS depreciation on pre-2012 vintages. Also, the Authority thoroughly reviewed CL&P's proprietary tax returns filed for 2011 and 2012. Response to Interrogatory AC-10. No information in those returns support any prior period adjustments that would warrant the August 2013 reduction to deferred tax balance in Account 28200.

The Authority is aware of the Company's compliance filing dated August 1, 2013, in which CL&P requested an automatic change to its method for accounting for certain retirement costs by filing Form 3115. This automatic election request was filed on July 10, 2013, with the IRS. CL&P stated that the request for an automatic change in accounting method is to simplify its tax accounting of certain retirement costs through a general asset account election. Response to Interrogatory AC-97 Second

Supplemental, Attachment 2. The Form 3115 referenced was filed protected and not entered into the record in this proceeding. Nevertheless, the Authority evaluates the non-public data and is concerned that the information contained therein actually contradicts the Company's testimony that a change in accounting method did not occur in 2012. According to the Company, the August 2013 true-up adjustment that reduced the ADIT balance in Account 28200 was to reverse estimated deferred taxes recorded in 2012 to reflect a change to a shorter retirement schedule that did not occur.

The Company testified that it recorded larger deferred taxes in Account 28200 in 2012 under the assumption that the tax retirement schedule would be decreased thereby increasing tax depreciation deductions in its 2012 tax returns. In actuality, the Company did the opposite by extending the retirement schedule for certain asset categories and hence, reduced tax depreciation deductions in its 2012 tax returns. The Authority finds it improbable that the Company would forecast and booked additional deferred taxes using a shorter retirement schedule for 2012, which is known to have 50% bonus depreciation and also subsequent to 2011 with 100% bonus tax depreciation deduction. As previously stated, the Authority finds that the additional deferred taxes recorded in Account 28200 in 2012 was in line with expectations, was not overstated and did not warrant the August 2013 reduction adjustment. Also, the Authority determines that the information in the non-public Form 3115 not only contradicts the Company's assertion, but the figures therein are applicable to transmission as well as to distribution operations. Furthermore, the Authority finds that the level of taxable income adjustment made therein did not support the August 2013 true-up adjustment to the distribution ADIT recorded in Account 28200.

A review of an exhibit showing the actual income taxes that the Company paid shows that CL&P's NOL position grew to $118.004 million in 2012 compared to $19.939 million in 2011. Response to Interrogatory OCC-260, Attachment 1. This does not support the position that deferred tax estimates for 2012 were overstated and need to be adjusted in August 2013. Conversely, the exhibit supported the position that a significantly higher tax depreciation was deducted in 2012, which is supported by the 2012 tax return filed under protective order and the PURA AR-13 Attachment. The Authority opines that the higher tax depreciation deductions in 2012 support the booked ADITs increase in 2012. The Authority therefore considers the August 2013 true-up adjustment reducing the deferred tax amount in Account 28200 to be improper and should be reversed.

Based on its review of information provided in Response to Interrogatory OCC-46 Attachment 1, the Authority performed its own analysis of ADIT related to distribution plant for 2012 and 2013 as depicted in the table below:

Table 11

Analysis of Distribution Plant ADIT for 2012 and 2013
($000)

Descriptions	**CYE 2012**	**CYE 2013**
Gross Distribution Plant	4,670,378	4,915,903
New Plant Additions	324,484	289,038
Existing Gross Plant	4,345,894	4,616,865
Federal Tax Depreciation – New Additions*	124,115	110,557
Federal Tax Depreciation – Existing Plant**	202,805	210,775
Total Federal Tax Depreciation	327,020	321,332
Less Book Depreciation***	(76,568)	(85,972)
Federal Timing Differences	250,452	235,360
Federal Deferred Taxes (35%)	87,658	82,376
State Total Tax Depreciation (5% of Gross Plant)	233,519	245,295
Less Book Depreciation***	(76,568)	(85,972)
State Timing Differences	156,951	159,323
State Deferred Taxes (9%)	14,126	14,339
Total Deferred Taxes - Federal Plus State	101,784	96,715
Reported ADIT Activities Per AC-9 Attachment 1	103,246	(46,113)
Variances	(1,462)	142,828

*Assumes 70% of new plant additions qualify for 50% bonus depreciation allowances in 2012 and 2013.
**Assumes 5% tax depreciation rate for existing plant not subject to bonus depreciation deductions in 2012 and 2013.
***Cost of Removal was removed from the total book depreciation activity amounts.

Based on the conservative assumptions that only 70% of the new plant additions qualified for bonus tax depreciation deductions and a normal tax depreciation rate of 5%, the Authority calculated a federal tax depreciation deduction of approximately $327.020 million for 2012. This amount is significantly less than the $384,142,472, which the Company reported as the actual distribution plant-related tax depreciation deduction for 2012. Using these cautious assumptions, the Authority also determined total deferred tax accretion of approximately $101.784 million for 2012. The amount aligns with the $103.246 million of additional ADIT that CL&P reported for 2012 and does not support the assertion that excess deferred taxes were recorded in Account 28200 in 2012. For the existing distribution plant and the total new plant additions of approximately $613.522 million in 2012 and 2013, the Authority establishes total additional deferred taxes of approximately $198.499 million. For these two years, with 50% bonus tax depreciation allowances, CL&P reported a total deferred tax increase of approximately $57.133 ($103.246 - $46.113) million. Based on its analysis and discussions above, the Authority concluded that the August 2013 entry that reduced the ADIT balance in Account 28200 by $124,742,248 is incorrect and unsubstantiated.

In its Written Exceptions, CL&P stated the PURA's adjustment to reverse the Company's August 2013 plant-related ADIT adjustment of $124,742,248 in Account 28200 is a mistake because the Authority made incorrect assumptions or followed incorrect accounting practice in assessing the purpose and effect of the adjustment.

According to the Company, the Authority misunderstood the election made by CL&P under IRS regulations in 2013 that actually resulted in a longer tax depreciation period and the accounting treatment of the change. The Company indicated that it did not change to a shorter retirement schedule in 2012. CL&P Written Exceptions, p. 30.

The Company claimed that the balance in Account 28200 as of December 31, 2012, estimated based on transactions occurring in plant assets (retirements, additions and basis adjustments), and the expected deductions under the tax law related to those plant assets. The Company also stated that its computation of tax depreciation expense assumed the traditional retirement schedule, not a shortened retirement schedule, for all asset categories. According to CL&P, the Authority incorrectly assumed the Company used a shortened retirement schedule instead of its traditional retirement schedule in 2012. CL&P Written Exceptions, pp. 31-33.

Contrary to its testimony in this proceeding that the August 2013's true-up adjustment of $124,742,248 in Account 28200 was made so that the deferred taxes on the books agree with the final amounts in its 2012 tax returns, the Company stated that the adjustment amount is made up of the following items:

1. A $74 million reclassification from Account 28200 (deferred tax liability) to Account 28399 (deferred tax liability) to properly distinguish plant-related timing differences from other non-plant related timing differences. The amount transfer Account 28399 has no impact to customers as both accounts work as an offset to rate base. Regardless of the reclassification, this amount was included in rate base as of December 31, 2012.

2. A $47 million decrease to deferred tax liability in Account 28200, which is the result of the Form 3115 Method Change. This change extended the retirement period of certain asset categories for tax purposes creating a smaller depreciation deduction for tax purposes than was expensed for book purposes. The reduction in the liability amount in Account 28200 effectively reduced the timing differences between book depreciation and tax depreciation, but did not represent a negative impact to customers. If the Company had not taken this step, the deferred tax asset recorded in Account 190 related to the NOL would simply have increased by $47 million, resulting in the same rate-base impact as the Company's adjustment.

3. A total of $4 million in minor, routine adjustments that reflect other changes to the estimated liability to what was actually filed on the 2012 tax return.

CL&P Written Exceptions, p. 36.

Finally, the Company stated that the IRS accepted its Form 3115 accounting change. However, CL&P indicated that the Authority's determination to reverse the August 2013 true-up adjustment of $124,742,248 in Account 28200 contradicts the IRS acceptance of the method change and effectively provided deferred tax benefit liability to customers where no such liability exists on the Company's books. According to the Company, the Authority's determination would create a violation of the normalization rules under the Internal Revenue Code. The consequences include an IRS determination that the Company cannot any longer claim accelerated tax depreciation or similar advantageous deductions permitted under the IRC. Therefore, CL&P requested that the determination in the Proposed Final Decision that reversed its August 2013 true-up adjustment of $124,742,248 in Account 28200 be reversed in the final Decision. CL&P Written Exceptions, pp. 37 and 38.

The Authority's determination is based on testimony provided in this proceeding. The Authority specifically asked the Company to provide the items that caused the August 2013 true-up adjustment of $124,742,248 in Account 28200. The Authority did not indicate that the Company changed to a shorter retirement schedule but that the deferred taxes recorded in Account 28200 was based on CL&P's reconciliation of projected or budgeted deferred taxes recorded in this account in 2012 to reflect the actual tax depreciation deducted in its 2012 tax returns. Tr. 09/25/14, pp. 2730-2734.

The information that the Company furnished in its Written Exceptions regarding the components of the August 2013 true-up adjustment of $124,742,248 in Account 28200 was never entered into record in this proceeding. Therefore, as part of the reopened proceeding discussed above, the Authority will afford the Company and other participants the opportunity to provide exhibits and testimony regarding each component of the $124,742,248 reduction to the ADIT in Account 28200. Similarly, the Authority will allow the Company to record as a regulatory asset the revenue impact of the $124,742,248 to be reconciled when it is finally determined if this amount will be allowed in rate base.

c. System Resiliency

The Authority finds that the revenue requirement proposed for the system resiliency plant additions was overstated. CL&P reported total system resiliency plant addition of $25.554 million in 2013. Schedule B-2.0 (A). The book depreciation related to this plant addition is $198,000. Schedule B-3.0 (A). For 2013, the Company reported ADIT associated with the system resiliency plant addition of only $252,000. Schedule B-7.0 (A). The Authority finds the 2013 ADIT amount related to system resiliency plant addition to be significantly low given that 50% bonus tax depreciation is applicable to 2013 plant additions. Thus, using the 15-year life tax schedule under the half-year convention, the Authority calculates the appropriate ADIT for the 2013 system resiliency plant addition as depicted in the table below.

Table 12

Calculations of ADIT for the 2013 System Resiliency Plant Additions ($000)

Gross Plant Additions*	$25,554,000
Federal Tax Depreciation, Including 50% Bonus Allowance	13,416,000
Book Depreciation**	198,000
Difference	13,218,000
Federal Deferred Tax Benefit at 35%	4,626,000
State Tax Depreciation	1,278,000
Book Depreciation**	198,000
Difference	1,080,000
Connecticut Deferred Tax Benefit at 9%	97,000
Total Deferred Tax Benefit	$ 4,723,000

* Schedule B-2.0 (A)
** Schedule B-3.0 (A)

The federal tax depreciation amount calculated above is 52.5% of the 2013 system resiliency plant addition of $25.554 million. It represents 50% of the 2013 system resiliency plant additions plus 5% of the remaining 50% plant additions not subject to the bonus depreciation allowance. The state tax depreciation amount calculated above is 5% of the 2013 system resiliency plant addition of $25.554 million. Based on the above calculation, the Authority determines that the average ADIT that the Company used to calculate average rate base was underreported by $4.471 ($4.723 - $0.252) million. Consequently, the Authority will similarly reduce the proposed rate base by $4.471 million for the underestimated ADIT connected with the 2013 system resiliency plant addition of $25.554 million.

In summary, the Authority will increase the Company's proposed average ADITs by $170.063 ($124.742 + $40.85 + $4.471) million. Thus, the Authority simultaneously reduces the proposed average rate base by the same amount. This adjustment will restore the normal unwinding of the plant-related deferred tax balance in Account 28200. This will occur as book depreciation deductions catch up and ultimately surpass tax depreciation deductions and fully restore the rate benefits of the increased ADITs derived from allowed significantly larger tax depreciation deductions.

3. Working Capital Allowance

a. Introduction

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

Schedule H-1.6 and its supporting Work Papers contained the results of and supporting calculations for the Company's lead/lag study. In conducting its study, CL&P used a stratified random sample of its retail accounts and calculated that it took an average of 40.95 days for CL&P to receive its revenues once service has been rendered based on data through December 31, 2013. WP H – 1.6a, p. 1. Included in this average revenue lag of 40.95 days is a service lag (time between service being provided and the reading of the meter) of roughly 15 to 16 days, a billing lag (time between the reading of the meter and sending out the bill) of two to three days and a payment lag (time between the bill being sent out and the payment being received by the Company) of approximately 23 days (41 days minus 15 days minus 3 days). Tr. 9/24/14, pp. 2444 and 2445. The Company also specifically studied and calculated the expense lead for payroll, payroll deductions, payroll incentives, CTA IPP's, non-bypassable federally mandated congestion costs (NBFMCC), conservation and renewable costs, uncollectible expense, other O&M, ten different categories of taxes, long-term debt, preferred stock and common equity. Based on these calculations and assumptions made regarding the expense lead for other expense categories such as depreciation and amortization, and pension, the Company calculated a cash working capital requirement of $17,230,000 based on a net lag of approximately 3.20 days for the Rate Year. Late Filed Exhibit No. 3, Schedule H-1.6 – Revised. The Authority reviewed CL&P's allowance for working capital request for the Rate Year and finds it acceptable except as discussed below.

b. Non-Cash Items

In its pre-filed testimony and brief, the OCC argued that non-cash expenses should not be part of the lead/lag study because they do not involve an outlay of cash and are excluded by some regulatory jurisdictions in the determination of a working capital allowance. Schultz PFT, pp. 12-15; Brief, pp. 46-49.[7] The OCC also argued that inclusion of non-cash expenses such as depreciation in the cash working capital allowance over compensates the Company by allowing it a double return on the expenses, even when such expenses reduce rate base. Brief, p. 48. To demonstrate

[7] The OCC also expressed concerns with the Company's calculation of expense leads for certain payroll check items, such as payroll taxes and employee deductions, and for income taxes, but made no adjustments related to these concerns. Schultz PFT, pp. 14 and 15, Exhibit_(L&A-1); Brief, p. 47, Schedule B-3, p. 1.

this, the OCC provided a hypothetical where a $100 asset is depreciated over a year. Id. In the hypothetical, the OCC contended that the Company is overcompensated if it gets a return on the average asset in rate base, recovery of the depreciation expense and a working capital allowance on the expense. In reviewing these assertions and contentions by the OCC, the Authority first considered whether ratemaking treatment creates a carrying cost for CL&P relative to the non-cash expenses. When these expenses reduce rate base, the Company is deprived of the return that investment in rate base affords. If there is a lag between the reduction in rate base and the receipt of revenues recovering the expense, a carrying cost is incurred by the Company for the time of the lag. As such, it is appropriate for these “non-cash” expenses to be part of a working capital allowance.

The Authority also considered whether inclusion in the lead/lag study as proposed by CL&P over-compensates the Company for the carrying cost of non-cash items. In order for the Company to be overcompensated, the inclusion of non-cash items in the lead/lag study would need to create a situation where a rate base item is still receiving a return after the item has been recovered from ratepayers. In the OCC’s hypothetical and as understood by the Authority, the $100 asset is depreciated over the course of a year so that the Company does not fully recover its investment in the asset until the end of the year when it has billed for the last portion of the asset’s depreciation expense. As such, it is appropriate for the Company to receive a return on the un-depreciated portion of the asset. In addition, if there is a lag between when the asset in rate base is reduced through depreciation and when the Company receives its cash from ratepayers, an additional return requirement is created. It is this additional return requirement that is provided by inclusion of the depreciation expense (and other non-cash expenses) in the lead/lag study. Finally, as the asset is removed from rate base it is necessary that the depreciation expense itself be recovered from ratepayers. As such, the three piece recovery through the asset in rate base, depreciation expense and as part of a working capital allowance is necessary to keep the Company whole and not overcompensated.[8] The lead/lag study proposed by the Company assumes and/or calculates that depreciation expense (and expense related to amortization and deferred taxes) results in a reduction to rate base after 15 days on average and that funds for this expense are received 25.95 days later. Late Filed Exhibit No. 3, Schedule H-1.6 – Revised. The Authority finds these assumptions and/or calculations appropriate and will allow non-cash items in the lead/lag study as proposed by the Company.

c. Revenue Lag on Costs Recovered through Adjustment Clauses that Use Billed Revenues

In developing the revenue lag for the Company, CL&P included a service lag to account for the time between service being rendered and meters being read. Tr.

[8] In its Written Exceptions, the OCC reasserted that inclusion of depreciation and other “non-cash” expenses in the lead/leg study constitutes a double counting since these costs are already in rate base and earning a return. OCC Written Exceptions, p. 39. In making this argument however, the OCC fails to realize that the lead/lag study only allows a working capital allowance for “non-cash” expense for the period of time when the expense is out of rate base and prior to recovery from ratepayers. As such, there is never a time when the “non-cash” expense is both in rate base and part of the working capital allowance.

9/24/14, pp. 2444 and 2445. While the Company did not specifically break out the service lag from its revenue lag of 40.95 days, based on billing cycles of 27 to 33 days and 12 months in a year, a reasonable estimate of the service lag would be 15.21 days [(365 ÷ 12) ÷ 2]. Tr. 9/24/14, p. 2445. While a service lag is appropriate for revenues associated with most expense categories, it is not appropriate for revenues associated with costs recovered through adjustment clauses that use billed revenues. These types of clauses recover costs based on sales billed during the month, not on sales accrued or delivered during the month. As such, meters are read during the month and trued up through the adjustment clause for service provided during the month. This action by these clauses effectively aligns meter reads with service rendered and eliminates the service lag. Tr. 9/24/14, pp. 2445-2451. The Company identified three of its adjustment clauses as using billed revenues to recover costs. They are: the Competitive Transition Assessment (CTA), the Systems Benefit Charge (SBC) and the NBFMCC. Late Filed Exhibit No. 67. These clauses recover $30,860,000, $41,418,000 and $189,702,000 in Rate Year costs, respectively. Late Filed Exhibit No. 3, Schedule H-1.6 Revised; Tr. 9/24/14, pp. 2441-2443, 2503 and 2504; November 5, 2014 Decision in Docket No. 99-03-36RE22, PURA Determination of The Connecticut Light and Power Company's Standard Offer – 2013 Reconciliation of CTA and SBC, p. 7. For cost recovered through these clauses, meter reads are centered on the midpoint of the month or billing cycle for service centered on the midpoint of the month or billing cycle. Tr. 9/24/14, p. 2446. Therefore, the Authority reduces the revenue lag associated with these costs by 15.21 days. This adjustment and the reasons for it are similar to an adjustment the Authority made in its Decision dated June 29, 2011 in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules (June 29, 2011 Decision), for costs recovered through the purchased gas adjustment clause (PGA). June 29, 2011 Decision, pp. 36 and 37.

In its Brief, the Company attempted to distinguish the PGA from the CTA, SBC and NBFMCC by asserting that the latter clauses have a lack of consistency in the sales growth, a lack of monthly reconciliation, that the change from using accrued revenues to using billed revenues is onetime in nature, that they will operate with a decoupling mechanism and that there is a greater lag between when payment is received and when payment clears for CL&P. CL&P Brief, pp. 91 and 92. Based on these alleged differences, the Company concludes that there is no on-going beneficial timing difference to CL&P from using billed revenues to collect costs in three of its adjustment clauses. While the alleged differences may or may not apply, they do not impact the revenue lag difference between using billed revenues to recover costs vs. using accrued revenues to recover costs. This is because for any given period and on average, billed revenues are billed at midpoint of the period and accrued revenues are only accrued at the midpoint of the period to be billed at the end of the period. Relative to accrued costs, this means that billed revenues are 15 or so days closer to being received by the Company [30 (end of period) minus 15 (midpoint of period) equals 15 days (timing benefit from using billed revenues)]. This timing benefit is not impacted by the consistency of sales growth, the timing of reconciliations (provided carrying costs are included), the onetime nature of the change from accrued revenues to billed revenues (the benefits continue as long as billed revenues are used), the presence of a decoupling mechanism or the length of other lag components in the revenue lag. As such, despite the Company's objections, a 15.21 day reduction to the revenue lag associated with costs recovered by the CTA, SBC and NBFMCC is appropriate.

d. Adjustments to Expense Amounts

In addition to adjustments to the lag days for some expense categories, the Authority also made adjustments to the amount of expenses or income allowed for ratemaking purposes. These adjustments are detailed throughout this Decision and impact the working capital allowance 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.

e. Conclusion

Based on the adjustments detailed above related to working capital, the Authority calculates a working capital allowance for the Company of $15,361,000 for the Rate Year, including the 15 basis point ROE penalty. This amount is based on a Rate Year net lag of 3.01 days and is $1,869,000 less than the $17,230,000 proposed by the Company. As such, the Authority reduces the working capital allowance $1,869,000 for the Rate Year. If and when the ROE penalty goes away as allowed by this Decision, the working capital allowance becomes $14,779,000, based on a net lag of 2.89 days, and is $2,451,000 less than the $17,230,000 proposed by the Company.

4. Reserves – Net of Deferred Income Taxes

In its Applications, CL&P reported total net regulatory liabilities or reserves of $37.148 million for the test year ending December 31, 2013, $36.915 million for the proforma period ending December 31, 2014, and $42.569 million for the proposed Rate Year ending December 31, 2015. Schedule B-8.0. Hence, the Company originally reported as an offset to rate base average total net reserves of $39.86 million for the Rate Year. Schedule B-8.0. In its updated filing, CL&P reported total net reserves of $37.728 million for the proforma period ending December 31, 2014, and $43.3829 million for the proposed Rate Year ending December 31, 2015. Late Filed Exhibit No. 3, Schedule B-8.0 Revised. The updated total average net reserves for the Rate Year is $40.555 million. Id., Schedule B-1.0 Revised.

The total average net reserves for the Rate Year included average net storm reserves of $7.689 million. Late Filed Exhibit No. 3, Schedule B-8.0 Revised. Based on the discussions in Section II.C.13, Storm Reserve, the Authority disallowed the recovery of $6 million of storm reserves in O&M expenses. Thus, the Authority will reduce the average net reserves by $1.775 ($6 / 2) X (1 - 0.4085)) million. Conversely, the rate base for the Rate Year is increased by $1.775 million.

5. Conclusion on Rate Base

The rate base approved in this Decision is $3.233 billion as identified in Section III.V.B.

C. EXPENSES

1. Depreciation

A depreciation rate study calculates the annual depreciation rate. The depreciation rate 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. The Company stated that the Test Year depreciation expense was $107 million and the projected Rate Year 2015 plant depreciation and amortization expense is $140 million. Application, Schedule C-3.32. CL&P filed a depreciation rate study, conducted by Mr. Spanos of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming), for utility plant owned and operated by CL&P as of December 31, 2013 (2013 Study).

a. General Concepts of Depreciation

Since the depreciation expense represents the annual recovery of the capital investment, the asset base of the utility is diminished with each year. The amount of depreciation that has been taken is booked in an account called the accumulated provision for depreciation, also known as the booked reserve.[9] All depreciation expense, retirements, cost of removal and gross salvage are booked in the booked reserve. The accumulated provision for depreciation, or booked reserve, serves as a "running total" of the extent to which individual assets or groups of assets have been depreciated. The theoretical reserve[10] is a calculation of what the depreciation reserve should be based on the current estimates of average service life (ASL), survivor curve and net salvage estimate. The comparison between the booked reserve and the theoretical reserve provides a metric of the accuracy of past depreciation rates.

In the case of a regulated utility, recovery of investor–supplied capital is dependent upon allowed revenues, which are dependent upon approved levels of the depreciation expense. Periodic reviews of depreciation rates are essential to the achievement of timely capital recovery for a regulated utility. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The ASL of a vintage is a statistic that will not be known with certainty until all units from the original placement have been retired from service. Therefore, a vintage ASL must be estimated initially and periodically revised as indications of the eventual ASL becomes more certain. A mathematical description of survival functions or survivor curves of retirement acting upon a plant category is determined from an estimation of service life statistics and an analysis of past retirement experience. The life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve to predict the expected remaining life of property units still exposed to the forces of retirement. The amount of

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[9] Booked reserve is also known as recorded reserve or actual reserve.
[10] Theoretical reserve is also known as required reserve.

weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category.

The level of asset grouping identified in the broad group procedure is the total plant-in-service from all vintages in an account. Each vintage is estimated to have the same ASL. The remaining life of each vintage is estimated from a projection life curve and the attained age of the vintage. The average remaining life for a broad–group plant account or rate category is a direct, dollar–weighted average of the remaining life of each vintage. The weights used in this calculation are the vintage survivors at the beginning of the study year.

Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are estimated parameters of a depreciation system that are subject to future revisions. Plant accounting data is utilized to conduct a statistical analysis of past retirement experience and analyzed to determine the relationship between retirements and realized gross salvage and cost of removal. An estimate of the net salvage rate applicable to future retirements is obtained from an analysis of the gross salvage and cost of removal realized in the past.

An analysis of past experience and trends over time provide a baseline for estimating future salvage and cost of removal. Consideration should be given to events that may cause deviations from net salvage realized in the past such as the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past. Judgment of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials were used in developing estimates of the future. 2013 Study, Exhibit JJS-2, p. IV-2. Average net salvage rates are estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements of the surviving plant with the estimated future net salvage rate.

Included in the depreciation study is an analysis of the adequacy of the booked depreciation reserve. The purpose of such an analysis is to compare the current balance in the booked reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the theoretical or required reserve and the booked reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are commonly maintained by various account classifications, the total booked reserve in relation to the sum of account computed reserves is a good indicator of the adequacy, or inadequacy, of booked reserves. Differences between theoretical and booked reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in depreciation reviews. Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system.

b. CL&P 2013 Study

CL&P filed the 2013 Study to estimate the appropriate annual depreciation accruals for CL&P's plant-in-service as of December 31, 2013. Three elements – method, procedure and technique – are needed to describe a depreciation system. Since 2009, CL&P has been using a depreciation system composed of the straight line method, ASL procedure, and remaining life technique. 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 remainder of this section describes the 2013 Study performed by Gannett Fleming.

A depreciation study was completed in 2009 for the 2009 CL&P Rate Case (2009 Study) for properties in service as of December 31, 2008. The Company's accounting policy has not changed since that study. The 2013 Study requests an annual depreciation expense of $138.8 million when applied to plant as of December 31, 2013. 2013 Study, pp. 6 and 7. Table 13 shows the results from the 2013 Study that includes the amortization approved to correct for the $380.5 million reserve imbalance seen in the 2009 Rate Case.

Table 13

Summary of 2013 Depreciation Expense ($000)

		ANNUAL ACCRUAL					
Function	Original Cost	Rate (%)	Amount	7 Year Amortization	Remaining Life Amortization	Total Adjusted	Adjusted Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(4)+(5)+(6)	(8)
Distribution	4,455,939	2.93	130,402	(10,305)	(8,491)	111,605	2.50
General Plant	231,658	3.34	7,733	(264)	(218)	7,250	3.13
Unrecovered Reserve Amortization			674			674	
Transportation Equipment	61,450						
Nondepreciable Plant	161,450						
Total Plant-in-service	4,910,498		138,810	(10,570)	(8,710)	119,530	

2013 Study, Exhibit JJS-2.

Table 14 provides a summary of the changes in annual rates resulting for total depreciable plant from adoption of the parameters and depreciation system recommended in the 2013 Study based on total plant investments of $4.7 billion.

Table 14

Current and Proposed Depreciation Annual Accruals

Account	Original Cost	Proposed Annual Accrual	Current Annual Accrual	Increase/(Decrease)
(1)	(2)	(3)	(4)	(5)=(3)-(4)
Distribution	$4,455,939,516	$111,605,156	$80,454,721	$31,150,435
General Plant	$231,658,093	$7,250,386	$7,674,419	($424,033)
Unrecovered Reserve Amortization		$674,989	0	$674,989
Total Depreciable Electric Plant	$4,687,597,608	$119,530,531	$88,129,140	$31,401,391

2013 Study, Exhibit JJS-3

As of December 31, 2013, the total booked reserve for the Company was $1.103 billion and the theoretical reserve is $1.17 billion, for a difference of $67 million. When the book reserve is less than the theoretical reserve as in the current case for CL&P, it means that the depreciation rates used in the past were too low. Plant was being depreciated at a slower rate than it should have been. Mr. Spanos stated that this level of reserve imbalance is insignificant relative to the level of reserve. Tr. 9/2/14, p. 715.

CL&P requested an increase of $30 million (Schedule C-3.32; LFE-3, Sch. 3.0 (revised) line 59). This increase was due to changes in life parameters, net salvage accruals, and resulting changes in reserve amortizations. CL&P Brief, p. 43. An increase in the depreciation expense in the amount of $18.5 million was caused by changes in net salvage. Further, the changes in life and net salvage parameters in the 2013 Study resulted in a $66 million deficiency in the reserve balance. For total depreciable plant, the actual book reserve is $1.103 billion and the theoretical reserve is $1.169 billion. 2013 Study, Exhibit JJS-4a. Therefore, a $16.2 million increase in expense was included to correct for the deficiency in the theoretical reserve. Spanos PFT, p. 15. CL&P testified that the $66 million reserve imbalance would be distributed to the individual vintages and recovered over the remaining life. Tr. 9/2/14, pp. 689 and 690.

c. Positions of the OCC and the AG

The OCC and AG recommended a reduction of $19.5 million in depreciation expense due to adjustments to ASL parameters, net salvage parameters and adjusting the amortization periods for six software accounts. OCC Brief, p. 81; AG Brief, p. 12. The OCC contended that multiple adjustments need to be made to CL&P's proposed depreciation expense. First, the OCC proposed adjustments to CL&P's analyses of mass property life parameters for two accounts: Account 362 – Distribution Station Equipment and Account 365 – Overhead Conductor and Devices. OCC Brief, pp. 91 and 95. Second, the OCC proposed adjustments to mass property net salvage values for four accounts: Account – 362 Distribution Station Equipment; Account 364 – Poles, Towers and Fixtures; Account 367 – Underground Conductors and Devices; and

Account 367 – Services. Pous Revised PFT, p. 31. Third, the OCC recommended extending the amortization period for 6 software systems from a 10-year amortization period to a 15-year amortization period and that any new software plant additions be amortized over a 15-year period. OCC Brief, p. 108. Based on these adjustments, the OCC recommended a total reduction of $19.5 million in depreciation and amortization expense. Pous Revised PFT, p. 6. In addition to these adjustments, the OCC argued that CL&P has not met the burden of proof required to support its depreciation expense request. OCC Brief, p. 82.

The AG claimed that the 2013 Study understates the ASL of its physical plant and overestimates its future negative net salvage costs. AG Brief, p. 12. The AG also supported the OCC's recommendation for extending the amortization period of specific software systems to 15 years. Id., p. 15.

d. Analysis

The accounts under dispute for mass property life parameters are Account 362 - Station Equipment and Account 365 – Overhead Conductors and Devices. The accounts under dispute for net salvage parameters are Account 362 – Distribution Station Equipment; Account 364 – Poles, Towers and Fixtures; Account 367 – Underground Conductors and Devices; and Account 369 – Services. These disputed accounts are addressed below.

i. Mass Property Life Parameters

There is no dispute that the calculation of annual depreciation expense based on the straight line method used in the 2013 Study requires the estimation of survivor curves. Both the OCC and the Company proposed to update survivor curves for Account 362 and Account 365 from the existing ones used to determine depreciation expense in the 2009 Study.

The OCC proposed adjustments to two mass property accounts, Account 362 - Distribution Station Equipment and Account 365 – Overhead Conductor and Devices. Table 15 shows a summary of the OCC and CL&P proposed survivor curves. The current survivor curves used for determining depreciation expense are 50-R2 for Account 362 and 50-SC for Account 365.

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Table 15

OCC's Recommended Mass Property Life Adjustments

Account	CL&P Proposed	OCC Proposed	OCC Adjustment	Dec. 31, 2013 Impact
362	51S0	54S0	3	$1,084,726
365	44O1	48L0	4	$3,671,710
Total				$4,756,436

Pous Revised PFT, p. 10.

The OCC's witness indicated that these adjustments were based on: 1) an independent review of the actuarially derived life indications; 2) information provided by the Company's personnel; 3) information obtained during discovery; and 4) from previous experience in "performing hundreds of depreciation analyses." Pous Revised PFT, pp. 10 and 11.

(a) Account 362 – Station Equipment

Account 362 – Station Equipment includes the following facilities: control equipment such as transformers, batteries, remote relay boards and connections; primary and secondary voltage connections and associated equipment; switching equipment; switchboards; fixed and synchronous condensers; bus compartments; conduit; conversion equipment; fences; foundations and settings; and general station equipment.

The existing survivor curve used to determine the depreciation expense for this account is 50R2. The Company proposed a 51S0 survivor curve and the OCC proposed a 54S0 survivor curve. 2013 Study, Exhibit JJS-2, p. VII-13; Pous Revised PFT, p. 19.

The OCC argued that CL&P's proposed survivor curve of 51S0, understates the realistic ASL. Pous Revised PFT, p. 19. The OCC further contended that from an actuarial standpoint, historical data for experience bands of 1916-2013, 1964-2013 and 1998-2013 indicate a significant trend towards a longer ASL that is not accounted for by the Company's analysis. Pous Revised PFT, pp. 20-23.

The Company justified use of its survivor curve by saying that "there is a plan to upgrade substation equipment more aggressively in the next few years to handle load requirements and technology advancements" which supports an ASL of 50 years. Response to Interrogatory OCC-001. Further, while station equipment in general is experiencing slightly longer ASL, relay equipment will see a higher level of early retirements. Response to Interrogatory OCC-003. The OCC argued that relay equipment is only a 7% investment in this account and should not restrict "a realistic increase in ASL for this account." Response to Interrogatory OCC-022; Pous Revised PFT, p. 23. The OCC further argued that the early retirement of relay equipment is already reflected in the historical data. Pous Revised PFT, p. 23.

The Company contended that the overall experience band of 1916-2013 should be used in this case for determining the most appropriate survivor curve. Spanos Rebuttal, p. 20. The Company argued that the 1998-2013 experience band is not indicative of future trends for this account because from 1999-2003, there was a focus on retiring older assets which would cause the retirements as a relationship to exposure to be lower. The Company claimed that this trend will not continue since there will be a focus on substation reliability work in the next 5 years that will result in retirements of not only old assets, but also of assets in the 30- to 40-year range. Tr. 9/2/13, pp. 698 and 699. The Company also claimed that, in addition to the primary reasons for past retirements – such as failure, wear and tear, load and demand – reliability and system integrity have become the dominant causes of retirement and the more technology-based assets can cause a higher percentage of retirements. Response to Interrogatory

OCC-007. The Company also showed that retirements have increased annually in the 2009-2013 time period to an average amount of $3.8 million, as compared to an average amount in the prior five years of $1.3 million. Response to Interrogatory OCC-023; CL&P Reply Brief, p. 34.

The Authority concurs that the recent trends in the historical data for the 1998-2013 experience band data are not necessarily indicative of future retirements for this account. The Authority accepts the OCC's argument that there is an obvious trend in the data when all three experience bands are analyzed. In fact, the Company acknowledged that the 1964-2013 experience band is "representative of the database." Tr. 9/2/14, p. 695. Accordingly, the Authority determines that the historical data in the 1964-2013 experience band should be heavily weighted for this account. Therefore, the Authority finds the OCC's proposed 54S0 curve to be a better match to the 1964-2013 experience band as it best reflects the most accurate representation for life parameters for this account. This results in a $1,084,726 reduction in annual depreciation expense based on plant as of December 31, 2013. Pous Revised PFT, p. 23.

(b) Account 365 – Overhead Conductors and Services

Account 365 – Overhead Conductors and Devices includes the following facilities: Conductors; circuit breakers; ground wires and clamps; insulators; lightning arresters; railroad and highway crossing guards; splices; switches; and other line devices.

The existing survivor curve for this account is 50SC. The Company proposed a 4401 curve, which is a reduction in ASL of six years. The OCC proposed a curve of 48L0 which is a reduction in ASL of two years.

The OCC argued that its life curve combination is similar to the Company's curve, but that when "neither actuarial analysis nor information external to the historical data provides strong support for a change in ASL" then the existing parameter should be retained. OCC Brief, p. 95. Since the curve fits are similar, the OCC contended its curve is more appropriate since it does not result in a significant decrease in ASL. Pous Revised PFT, p. 25. The OCC further justified the use of its curve by noting that CL&P has not stated any changes in policies or practices that would warrant the six year reduction in ASL. The OCC also argued that the age of overhead conductors, with more than 50% over 40 years of age and at least 33% over the age of 50 years support the use of OCC's recommended curve. Finally, the OCC claimed that the recent storms experienced by CL&P may reduce the perceived ASL in the actuarial analyses. Id., pp. 27 and 28.

The Company argued that the L0 dispersion pattern for the OCC's proposed curve is unrealistic since its views overhead conductors as the longest lived asset for that account and that 90 to 100 years is an appropriate number for longest service life. Tr. 9/2/14, pp. 678 and 680. The OCC countered that insulator pins and posts have a longer service life than conductors and that "only $100 in assets out of a $1.2 billion account would need to live 160 years to validate an L0 dispersion pattern." Tr. 9/2/14,

p. 734. The Company stated that typically insulator pins and posts are replaced when the conductor is replaced. Tr. 9/2/14, p. 680.

The Authority finds that of the historical data for this account support the Company's statement that the longest lived assets range from 90 to 100 years. Spanos Rebuttal Testimony, p. 22. The Authority also finds that although the curves are similar, the Company's curve is a superior fit and the OCC's curve is only a better fit to the historical data for a portion at the tail end of the curve where neither party believes much emphasis should be placed. The Authority accepts the Company's life curve combination for this account.

ii. Net Salvage Parameters

The Company's net salvage estimates were based on "judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials." Spanos PFT, Exhibit JJS-2, p. IV-2. A negative net salvage percent occurs when cost of removal is greater than salvage return. The Company compiled historical data from 1999 through 2013. Id. The OCC agreed with the Company that averages of the historical data are not always representative of future net salvage. Pous Revised PFT, p. 32. These figures are important since these costs were incurred in practice. The Authority will use these figures to ensure that these costs will not be shifted to future customers of the Company. Table 16 below displays the 15-year historical average and the five-year moving average for net salvage costs. Negative net salvage percentages are displayed in parentheses.

Table 16

Average Net Salvage Values

Account	Overall Average	5-Year Average
362	(58)	(61)
364	(138)	(100)
367	(83)	(81)
369	(222)	(450)

Spanos Rebuttal Testimony, p. 24

CL&P argued that from 2009 – 2013, the Company has incurred larger costs of removal than has been accrued. This data presented in Table 17 below is derived from Spanos PFT, p. 14.

Table 17

Incurred vs. Accrued Cost of Removal

Year	Incurred	Accrued
2008	30,761,664	9,795,406
2009	19,744,032	12,239,899
2010	21,368,525	12,944,564
2011	30,401,991	13,585,052
2012	31,826,451	14,603,464
2013	25,699,305	15,520,100

The Company further argued that it should at least accrue for as much as it incurs and since it is a growing company, it should be allowed to accrue more than what it has been incurring. Tr. 9/2/14, pp. 702 and 703. The Company argued that the goal with net salvage recovery in this proceeding is to correct for the under recovery seen in recent years and to gradually move the Company towards full recovery. CL&P Reply Brief, p. 36. The Company expected that the net salvage values will need to be more negative in the future. Tr. 9/2/14, p. 716.

The OCC proposed net salvage adjustments to four Mass Property Accounts: 362 – Distribution Station Equipment; 364 – Poles, Towers and Fixtures; 367 – Underground Conductors and Devices; and 369 – Services. Table 18 summarizes CL&P's proposals and the OCC's recommended adjustments and their impact on the Company's proposed depreciation expense.

Table 18

Proposed Net Salvage Adjustments

Account	CL&P Existing	CL&P Proposed	OCC Recommended	OCC Adjustment	Impact
362 – Distribution Station Equipment	(30%)	(35%)	(25%)	(10)	$1,437,561
364 – Poles, Towers and Fixtures	(50%)	(60)%	(50%)	(10)	$1,143,856
367 – Underground Conductors & Devices	(10%)	(25%)	(15%)	(10)	$1,904,773
369 - Services	(20%)	(100%)	(50%)	(50)	$3,542,746
Total					$8,028,935

Pous Revised PFT, p. 31.

(a) Account 362 – Station Equipment

The existing net salvage approved for this account is -30%. The Company proposed a -35% net salvage and the OCC proposed a -25% net salvage value. Pous Revised PFT, p. 32. The OCC argued that the Company provided no valid basis to propose a more negative net salvage than the existing value. The OCC claimed that the Company's industry database better supports the OCC's proposed net salvage value of -25%. Id. The OCC further stated that transformers, which comprise 35% of the investment in this account, but only 23% of the dollar-related retirement activity should provide some positive salvage to offset cost of removal. The transformers also contain large quantities of copper, which should result in offsetting salvage. Id., pp. 32 and 33.

The Company argued that the value presented by the OCC would accrue less in depreciation expense for cost of removal than the Company incurred annually. Spanos Rebuttal Testimony, p. 26. The OCC, however, showed that its recommended level of cost of removal, when divided by the remaining life, exceeds the annual average cost of removal for the last three years by 24%. OCC Brief, p. 102. The OCC also contended that the high dollar cost transformers will have a less negative percentage level of net salvage than other types of assets when retired. Id., pp. 102 and 103.

Based on the most recent three year statistics for cost of removal, a -25% net salvage value will allow CL&P to accrue more than it incurs, while still providing room for growth. Therefore, the Authority accepts the OCC's recommendation of a -25% net salvage value for Account 362 – Distribution Station Equipment. This results in a $1,437,561 reduction in annual depreciation expense based on plant as of December 31, 2013. Pous Revised PFT, p. 34.

(b) Account 364 – Poles, Towers, and Fixtures

The existing net salvage approved under rates for this account is -50%. The Company proposed a -60% net salvage and the OCC proposed a -50% net salvage value.

The OCC contended that CL&P failed to adequately justify its increase in a negative net salvage for this account. The OCC recommended retaining the existing net salvage value of -50%. Pous Revised PFT, p. 34. It argued that major storms contributed to the higher costs of removal seen in recent years and that the Company's historical database better supports its net salvage value. The OCC maintained that recent major storms resulted in higher net salvage costs for this account, artificially increasing the negative net salvage levels. Id.

CL&P stated that most of the storm costs were removed when calculating net salvage parameters for the study since the Company "didn't want to have our going forward estimates to include that in our total salvage." Tr. 9/2/14, p. 704. The Company also stated that the STORMS software system, in use since 2006, allows for more accurately recording removal costs and factored into this net salvage value. Spanos Rebuttal Testimony, p. 28.

While the Company has shown that in general, it is incurring more salvage costs than it is accruing, there is no specific data on the record for Account 364 that supports an increase in the negative net salvage value for this account. In the Proposed Final Decision, the Authority accepted the Company's proposed -60% net salvage value for this account based on CL&P's claim that storm related costs were isolated from the historical data. However, in its Written Exceptions, the OCC noted that the Company did not remove the impact of recent storm costs from its proposal. OCC Written Exceptions, p. 21. Specifically, the Company acknowledged in Late File Exhibit No. 14 that the incurred cost of removal amounts set forth in Table JJS-1 on page 4 of Spanos PFT did not distinguish major storm related removal costs. Further, while the Company stated that the STORMS software system more accurately records removal and salvage costs, it admitted uncertainty as to how detailed the system is with isolating specific costs related to storm work. Tr. 9/2/14, pp. 708 and 709. Finally, the Company assigned removal costs in 2006 and 2007 to Account 364 from earlier years' retirements that were delayed in being recorded. Also, the Company undertook large projects that involved retirements from both Accounts 364 and 365 and assigned large amounts to Account 364 and very little to Account 365. Response to Interrogatory OCC-214.

The Authority finds that the Company did not provide adequate justification to increase the net salvage values for Account 364. The historical data does not clearly isolate major storm costs as the Company initially claimed. Further, salvage costs assigned to Account 364 in 2006 and 2007 were not necessarily associated with those years or with that specific account. Therefore, the Authority accepts the OCC's argument to retain the existing -50% net salvage value for Account 364 – Poles, Towers and Fixtures. This results in a $1,143,856 reduction in annual depreciation expense based on plant as of December 31, 2013. Pous Revised PFT, p. 36.

(c) Account 367 – Distribution Underground Conductors and Devices

The existing net salvage approved under rates for this account is -10%. The Company proposed a -25% net salvage value and the OCC proposed a -15% net salvage value. Both net salvage values proposed are well below the negative 83% over the last 15 years and the negative 81% from the most recent 5 years.

The OCC argued that the Company did not provide sufficient evidence supporting the -25% value outlined in the study. Pous Revised, PFT, pp. 38 and 39. The OCC contended that its proposed value is superior since most underground conductors are abandoned in place and that industry trends show more cables are installed in conduit rather than direct-buried. Id., p. 39. According to the OCC, this should result in lower cost of removal since retired cable in conduit can be pulled out when not retired in place. Id.

The Company countered that most conductor in conduit has only been placed in the last 30 to 40 years and that the ASL of this account is 50 years, so the overall impact of removing retired cable from conduit will not be seen for many years. Spanos Rebuttal Testimony, p. 29. The Company further argued that the practice of abandoning direct buried conductor is a practice that has not changed and is already reflected in the cost of removal statistics. Id.

The Authority finds the Company's net salvage value for this account to more accurately reflect the historical data and the outlook for net salvage in the near future. Therefore, the Authority approves the Company's net salvage value of -25%.

(d) Account 369 – Distribution Services

The existing net salvage approved under rates for this account is -20%. The Company proposed a -100% net salvage and the OCC proposed a -50% net salvage value.
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The OCC argued that the Company has not provided adequate justification for a five-fold increase in net salvage. OCC Brief, p. 106. The OCC also argued that the Company's claim that more services will be underground and will increase the negative net salvage is not supported by the industry database. Pous Revised PFT, p. 44. The AG opposed the increase and notes that "a negative net salvage of 100% means that for every dollar of plant invested, the Company expects to incur and additional dollar in the future to remove it." AG Brief, p.14.

The Company acknowledged that the five-fold increase does not necessarily appear gradual, but it is an appropriate change considering the historical indications that show a negative 222% net salvage over the last 15 years and a negative 450% net salvage from the most recent 5 years. Spanos Rebuttal PFT, p. 31; 2013 Study, Exhibit JJS-2, p. VIII-9. The Company also acknowledged that the negative 450% 5-year average for net salvage for this account is not appropriate. Spanos PFT, p. 30. The Company argued that the current negative 20% net salvage selected in the 2009 CL&P Rate Case was artificially low to correct the reserve imbalance. CL&P Response to Interrogatory OCC-218. The Company further argued that, recently, older than usual retirements have occurred for this account and that it therefore expects negative net salvage of 100% to 150%. CL&P Response to Interrogatory OCC-218.

The Authority finds the Company's request for an increase to negative 100% net salvage for this account is unsupported by the record. Specifically, when asked for support and justification for this increase in Interrogatory OCC-218, the Company provided only general expectations. Further, there is nothing in the 2009 CL&P Rate Case that supports the Company's claim that the current net salvage value was artificially low. The Authority therefore rejects the Company's request. The Authority accepts the OCC's recommendation of a negative 50% net salvage, which is more than double the current value. The Authority finds this value to more reasonably represent a gradual approach to full recovery for the Company. This net salvage value results in a $3,542,746 reduction in annual depreciation expense based on plant as of December 31, 2013.

iii. Software Amortization

The OCC argued that for Account 303 – Intangible Plant – Software, intergenerational inequity exists and that $44 million of investment in these systems is already amortized but is still in service. Pous Revised PFT, p. 47. This accounts for nearly 30% of the total investment. Id. The OCC recommended extending the amortization period of 6 accounts currently under a 10-year amortization period that are not fully amortized to have their amortization period extended to 15 years. Id., p. 48. The OCC also recommended the $14 million of additions to Account 303 in 2014 and 2015 be amortized over a 15-year period (Company Schedule B-2.1, line 23). Id., p. 49. The OCC further recommended that "any new plant additions subsequent to December

31, 2013 to which CL&P would assign a 10-year amortization period, also be assigned a 15-year amortization period." OCC Brief, p. 108. The OCC claimed that customers who are receiving the benefit of this software are not paying for it and that 30% of the entire software investment is fully recovered, but still used and useful. Response to Interrogatory OCC-348; Pous Revised PFT, p. 47. The OCC also argued that the base rate revenues recovered for an amortization expense become additional return on investment when the system that provides service is fully amortized. Pous Revised PFT, p. 48. The OCC claimed that CL&P ceases to record an increase to the amortization reserve when the individual system becomes fully accrued, but the Company still collects revenue dollars from customers. Id.

According to CL&P, software amortization was not covered in the 2013 Study as it was supported by the Company's accounting group. CL&P Reply Brief, p. 37. CL&P developed estimates for its software amortizations using its accounting group and Company IT professionals and the timeframes they apply are three, five and ten years. Tr. 9/2/14, pp. 709 and 710. CL&P agreed that some software systems have lasted longer than the original estimated life, but did not believe that the Company historically underestimates the useful life of its systems. Id., p. 711.

The Authority concurs that the amortization period is intended to be the period over which the investment is used and useful so that customers that receive the benefit of the asset pay for the asset. Pous Revised PFT, p. 46. The Company owns 67 software assets as of December 31, 2013. Of these, 45 have been fully amortized but are still in service. As mentioned above, this accounts for nearly 30% of the total software investment. However, all but one of the 45 systems cited above are assigned a 5-year amortization period. CL&P Response to Interrogatory OCC-348, Attachment 1. Those systems contributed the most to $44 million worth of plant still in service yet fully amortized. Therefore, the Authority finds it inappropriate to assign a 15-year amortization period for the Company's software systems that are currently assigned a 10-year amortization period since these systems have not contributed to the 30% of fully recovered investment. Further, even though 30% of the systems used by the Company are fully amortized, the OCC acknowledged that it is "reasonably" possible for some software to be taken out of service prior to the end of its amortization period. Response to Interrogatory CL&P-12. For these reasons, the Authority rejects the OCC's recommendation to impose a 15-year amortization period on the software systems that are currently assigned a 10-year amortization period. However, the Authority will adopt the OCC's recommendation that the Company perform a complete and well documented analysis of expected service periods for its existing and new software systems prior to its next rate proceeding. Pous Revised PFT, p. 49.

2. Payroll

The Company originally requested a Rate Year payroll expense of $135.881 million which includes both base and overtime payroll. Schedule C-3.26. Subsequently, the Company revised the request to $135.198 million, a decrease of $683,000 for reduced overtime due to the troubleshooters program. Late Filed Exhibit No. 3, Revised Schedule C-3.26 and Revised WPC-3.26.

a. Full Time Equivalent Positions (FTEs)

The requested Rate Year payroll expense of $135.198 million is for FTEs as of January 1, 2014. CL&P Brief, p. 27. The 4,435.8 requested Rate Year FTEs are comprised of CL&P employees and 26.2% of the cost of the employees working for the Northeast Utilities Service Company (NUSCO). NUSCO provides centralized accounting, environmental, legal, purchasing, security and other services to CL&P and the other affiliates of NU. Id. The Rate Year FTEs were calculated by beginning with the total FTEs as of January 1, 2014 (4610.8 FTEs) and subtracting the NUSCO 175 FTEs that were leaving due to the NUSCO IT reorganization. Id., p. 28. The Company claimed that between the closing of the merger in April 2012 and the end of the Test Year, the NU organization has already reduced staffing levels in other areas, with the savings reflected in the revenue requirement for this case. Joint Rebuttal Testimony of Bowes and Michelson, p. 15.

The Company further stated the positions that remain are needed to operate the distribution system and provide service to customers. Disallowing funding for 131.2 positions would have a substantial adverse impact on the Company's ability to execute its operational and business plan successfully for the Rate Year. Id. During the hearings, when asked to elaborate and explain this statement, the Company witness stated that as to a specific substantial impact he did not know. Tr. 9/12/2014, pp. 2305-2307. The witness went on to state that if the employee level was cut, the Company would have to find a way to handle that workload, which if not handled by one of its internal FTEs, would have to be handled by outsourcing, either as a temporary situation or by another contractor. Id.

The Company was also asked to provide an update on the total number of FTEs as of August 31, 2014. The total FTEs as of that date was 4,253.8. Late Filed Exhibit No. 55, Attachment 1, p. 1. The Company stated that between August 31, 2013 and August 31, 2014, 201 positions opened-up due to attrition. Id. Of the 201 open positions, CL&P is actively seeking to fill 101. Of the remaining 100 open positions, 68 are allocated to CL&P and 32 to NUSCO. In addition, the Company provided a listing of the 101 CL&P and NUSCO open/approved positions as of August 31, 2014. Id., Attachment 2, p. 1. The Company provided the status update as of September 5, 2014, for those CL&P and NUSCO May 31, 2014 Open Positions. Late Filed Exhibit No. 54, Attachment 1, p.1. The Company claimed that open positions are always filled; it does not have vacancy rate information, nor does it track that information. Tr. 9/12/2014, pp. 2295-2297.

The OCC originally proposed a reduction to the Company's requested payroll expense of $6,255,239. OCC Brief, p. 50. This reduction was based on an adjustment of 102 FTE positions for the remaining IT positions that had yet to be vacated. Id. Subsequently, the OCC revised its adjustment to correct the error associated with the actual number of IT positions remaining as of May 2014. Id. The revision, based on June 1, 2014 FTEs and a reduction of the original adjustment from 102 to 29 FTEs (due to the error in calculating the remaining IT employees), resulted in a recommended reduction to the payroll expense of $4,019,037. Id.

The OCC made a further revision to its recommended payroll expense reduction to reflect the FTE count as of August 2014 as shown in the response to Late Filed Exhibit No. 55. Id., p. 52. Using the FTE count as of August 2014, which is 80 positions less than the June 1, 2014 FTE count, the OCC recommended a reduction to payroll expense of $5,575,188. Id.

In its Reply Brief, the OCC recommended that payroll expense be reduced by $5,547,165. OCC Reply Brief, (L&A-1), Schedule 1. The OCC stated that despite the Company's claim that it plans to fill the vacant positions, the evidence clearly indicated the current level of 4,253.8 FTEs is 182 FTEs less than the 4,435.8 requested. From December 31, 2013 through August 31, 2014, the employee count declined from 4,610.8 FTEs to 4,253.8 FTEs and that with the exception of June 2014, each month showed a steady decline in FTEs. Further, the evidence clearly shows that the decline is continuing, and despite the Company's claim that positions are being filled, the net result is that further reductions have occurred. OCC Reply Brief, p. 3.

The AG stated that it supported many of the other downward adjustments to CL&P's rate request that were proposed by the OCC in this matter including a downward adjustment to full time employees. AG Brief, p.23.

The Authority finds that it is highly unlikely for the Company to not have any type of vacancy rate when it determines its payroll expense costs for ratemaking purposes. The fact that the Company stated that some positions take much longer to fill than others is evidence that there are some open positions at any point in time.

In its Written Exceptions, the Company acknowledged the Authority's legitimate concern about the need for the Company to develop a vacancy rate. The Company suggested a vacancy rate of 1.5% which equates to a reduction in the requested FTEs of 66.5. The Authority determines based on its analysis of the evidence presented in the instant proceeding that a reduction of 147 FTEs is more appropriate.

Therefore, the Authority reduces the requested FTE total, through the following adjustments, relative to the 82 active positions as of September 5, 2014 and for the 100 positions which have yet to be approved. Late Filed Exhibit No. 54; Late Filed Exhibit No. 55, Attachment 2, p. 1.

b. 82 Active Positions

Of the 82 active positions, 50 are CL&P and 32 are NUSCO. Fifteen of the 82 positions are listed as being in the reviewing/interviewing/recruiting process and 32 positions are listed as being internal transfers/positions. The Authority determines that these 47 positions are speculative hires or if they are filled from within the organization, are a shifting of payroll dollars from one cost center to another and therefore, are disallowed. The Company's reluctance to track FTE statistics and develop vacancy rates concerns the Authority as it is an appropriate measure for any company to maintain, especially when justifying recovery of an FTE level in a rate proceeding.

Of the 47 FTEs that are disallowed, 28.2 FTEs (47 x 60%) will be reflected as CL&P positions using an average expense base salary of $97,924,[11] benefits loader of 46.2% of base salary and a payroll taxes loader of 8.5% of base salary as provided by the Company in Late Filed Exhibit No. 72. Forty percent or 18.8 FTEs (47 x 40%) are NUSCO positions which are then allocated to CL&P using the Company's allocation factor of 26.2%. The allocated NUSCO FTEs being disallowed are 4.9 FTEs (18.8 FTEs x 26.2%). The disallowed 4.9 NUSCO FTEs will be reflected using NUSCO's average base salary of $87,279,[12] a benefits loader of 46.2% of base salary and a payroll taxes loader of 8.5% of base salary as provided by the Company.

Therefore, the payroll expense adjustment is $1,467,954 as shown in the table below.

Table 19

ADJUSTMENTS FOR "ACTIVE" FTES			
		Disallowed FTEs	Total
CL&P FTE Adjustments			
Expense Adjustment for 28.2 FTEs			
CL&P Average Base Salary	$97,924		
Base Salary Expense (46.03%)	$45,074	28.2	$1,271,099
NUSCO FTE Adjustments			
Expense Adjustment for 4.9 FTEs	$87,279		
NUSCO Average Base Salary			
Base Salary Expense (46.03%)	$40,175	4.9	$196,855
Total Disallowed Payroll Expense		33.1	**$1,467,954**

c. 100 Positions to be Approved

The Company stated it is looking to fill 100 positions, which are at various stages of review in the Company's Human Resources organization and within the businesses. Late Filed Exhibit No. 55, p. 2. Of the 100 positions, 68 are for CL&P and 32 are for NUSCO. Id., p. 1. Also, the Company is continually reviewing these additional open positions to ensure that the positions that are approved, sourced and ultimate hired are reflective of the Company's needs. Id. The Authority maintains that it is uncertain whether these 100 positions, which have yet to go through the approval process, will ever come to fruition as positions that will be filled before the Rate Year. The Authority reiterates its concern regarding the lack of a vacancy rate in determining an expected FTE level. Moreover, the Company stated that there still may be merger synergies,

[11] The average base salary of $97,924 for CL&P employees is the average of the three employee class base payrolls for the rate year as presented in responses to Interrogatories OCC-185 and OCC-186 [($103,970+$102,821+$86,981)/3].

[12] The average base salary of $87,279 for NUSCO employees is the average of the three employee class base payrolls for the rate year as presented in responses to Interrogatories OCC-185 and OCC-186 [($96,098+$92,883+$72,865)/3].

which have yet to be determined and that it is always looking for ways to improve efficiencies. Tr. 9/12/2014, p. 2308. The Authority is of the opinion that the synergies would result in a decrease to FTEs rather than creating a need for an increase in FTEs. Consequently, the Authority disallows the 100 positions, 68 for CL&P and 32 positions for NUSCO. CL&P's 26.2% allocation of the NUSCO positions results in a disallowance of 8.4 FTEs. The disallowance of payroll expense for these positions is $3,402,526 as calculated in the table below.

Table 20

ADJUSTMENT FOR 100 POSITIONS YET TO BE APPROVED			
		Disallowed FTEs	Total
CL&P FTE Adjustments			
Expense Adjustment for 68 FTEs			
CL&P Average Base Salary	$97,924		
Base Salary Expense (46.03%)	$45,074	68.0	$3,065,060
NUSCO FTE Adjustments			
Expense Adjustment for 8.4 FTEs			
NUSCO Average Base Salary	$87,279		
Base Salary Expense (46.03%)	$40,175	8.4	$ 337,466
Total Disallowed Payroll Expense		76.4	**$3,402,526**

d. Summary of Payroll Expense Adjustments

The total expense portion of payroll disallowed is $4,870,480. It represents a total of $1,467,954 for the active position disallowance and $3,402,526, which is the disallowance for the 100 positions yet to be approved.

e. Payroll Capitalization Adjustments

The Company capitalizes 53.97% of its payroll, which is the balance of payroll that is not expensed (100% - 46.03% expense). This capitalized portion is reflected in the Company's plant and rate base. It is necessary to adjust rate base for the portion of capitalized payroll that is being disallowed.

i. 82 Active Positions

The $1,721,170 of the disallowed capitalized portion of payroll for CL&P's 28.2 FTEs and NUSCO's 4.9 FTEs is calculated in the table below.

Table 21

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	Total
CL&P FTE Adjustments			
Capitalization Adjustment for 28.2 FTEs			
CL&P Average Base Salary	$97,924		
Base Salary Capitalization (53.97%)	$52,850	28.2	$1,490,358
NUSCO FTE Adjustments			
Capitalization Adjustment for 4.9 FTEs			
NUSCO Average Base Salary	$87,279		
Base Salary Capitalization (53.97%)	$47,104	4.9	$230,812
Total Disallowed Payroll Capitalization		33.1	**$1,721,170**

ii. 100 Positions to be Approved

The $3,989,449 of disallowed capitalized portion of payroll for the 68 CL&P FTEs and the 8.4 NUSCO FTEs is calculated in the table below.

Table 22

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	Total
CL&P FTE Adjustments			
Capitalization Adjustment for 68 FTEs			
CL&P Average Base Salary	$97,924		
Base Salary Capitalization (53.97%)	$52,850	68	$3,593,772
NUSCO FTE Adjustments			
Capitalization Adjustment for 8.4 FTEs			
NUSCO Average Base Salary	$87,279		
Base Salary Capitalization (53.97%)	$47,104	8.4	$ 395,677
Total Disallowed Payroll Capitalization		76.4	**$3,989,449**

f. Summary of Payroll Capitalization Adjustments

The total capitalized portion of payroll disallowed is $5,710,619. It represents a total of $1,721,170 for the active position disallowance and $3,989,449, which is the disallowance for the 100 positions yet to be approved.

g. Payroll Taxes

As a result of the adjustments made to the Company's payroll, the Authority makes the associated adjustments to the Company's payroll taxes. Just as the Company has payroll that is expensed and payroll that is capitalized, so does the Company have both expense and capitalized portions of its payroll taxes.

i. Payroll Tax Expense Adjustment

The disallowed portion of payroll tax expense is $413,968 ($124,775 + $289,193) as a result of the 33.1 active FTEs which are disallowed and the 76.4 disallowed FTEs for the 100 positions yet to be approved. The adjustment is calculated as shown in the tables below:

Table 23

EXPENSE ADJUSTMENTS			
		Disallowed FTEs	Total
CL&P Adjustments			
Expense Adjustment for 28.2 FTEs			
Base Salary Expense (46.03%)	$45,074		
Payroll Tax Loader (8.5%)	$3,831	28.2	$108,042
NUSCO Adjustments			
Expense Adjustment for 4.9 FTEs			
Base Salary Expense (46.03%)	$40,175		
Payroll Tax Loader (8.5%)	$3,415	4.9	$16,733
Total Disallowed Payroll Tax Expense		33.1	**$124,775**

Table 24

EXPENSE ADJUSTMENTS			
		Disallowed FTEs	Total
CL&P Adjustments			
Expense Adjustment for 28.2 FTEs			
Base Salary Expense (46.03%)	$45,074		
Payroll Tax Loader (8.5%)	$3,831	68.0	$260,508
NUSCO Adjustments			
Expense Adjustment for 4.9 FTEs			
Base Salary Expense (46.03%)	$40,175		
Payroll Tax Loader (8.5%)	$3,415	8.4	$28,685
Total Disallowed Payroll Tax Expense		76.4	**$289,193**

ii. Payroll Tax Capitalization Adjustment

The disallowed portion of capitalized payroll taxes is $485,390 ($146,300 + $339,090) for the 33.1 active FTEs which are disallowed and the disallowed 76.4 FTEs for the 100 positions yet to be approved. The calculations are shown in the tables below:

Table 25

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	Total
CL&P Adjustments			
Capitalization Adjustment for 28.2 FTEs			
Base Salary Capitalization (53.97%)	$52,850		
Payroll Tax Loader (8.5%)	$4,492	28.2	$126,681
NUSCO Adjustments			
Capitalization Adjustment for 4.9 FTEs			
Base Salary Capitalization (53.97%)	$47,104		
Payroll Tax Loader (8.5%)	$4,004	4.9	$ 19,619
Total Disallowed Payroll Taxes Capitalization		33.1	**$146,300**

Table 26

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	Total
CL&P Adjustments			
Capitalization Adjustment for 68 FTEs			
Base Salary Capitalization (53.97%)	$52,850		
Payroll Tax Loader (8.5%)	$4,492	68.0	$305,456
NUSCO Adjustments			
Capitalization Adjustment for 8.4 FTEs			
Base Salary Capitalization (53.97%)	$47,104		
Payroll Tax Loader (8.5%)	$4,004	8.4	$ 33,634
Total Disallowed Payroll Taxes Capitalization		76.4	**$339,090**

h. Benefits

As a result of the adjustments made to the Company's payroll, the Authority makes the associated adjustments to the Company's benefits using the benefits loader of 46.2% of base salary as provided by the Company in Late Filed Exhibit No. 72. The adjustments include both the expense and capitalized portions of benefits.

i. Benefits Expense Adjustment

The disallowed portion of benefits expense is $2,250,146 ($678,190 + $1,571,956) as a result of the 33.1 active FTEs which are disallowed and the 76.4

disallowed FTEs for the 100 positions yet to be approved. The adjustment is calculated as shown in the tables below:

Table 27

EXPENSE ADJUSTMENTS			
		Disallowed FTEs	Total
CL&P Adjustments			
Expense Adjustment for 28.2 FTEs			
Base Salary Expense (46.03%)	$45,074		
Benefits Loader (46.2%)	$20,824	28.2	$587,242
NUSCO Adjustments			
Expense Adjustment for 4.9 FTEs			
Base Salary Expense (46.03%)	$40,175		
Benefits Loader (46.2%)	$18,561	4.9	$90,948
Total Disallowed Benefits Expense		33.1	**$678,190**

Table 28

EXPENSE ADJUSTMENTS			
		Disallowed FTEs	Total
CL&P Adjustments			
Expense Adjustment for 28.2 FTEs			
Base Salary Expense (46.03%)	$45,074		
Benefits Loader (46.2%)	$20,824	68.0	$1,416,045
NUSCO Adjustments			
Expense Adjustment for 4.9 FTEs			
Base Salary Expense (46.03%)	$40,175		
Benefits Loader (46.2%)	$18,561	8.4	$155,911
Total Disallowed Benefits Expense		76.4	**$1,571,956**

ii. Benefits Capitalization Adjustment

The disallowed capitalized portion of benefits is $2,638,342 ($795,185 + $1,843,157) as a result of the 33.1 active FTEs which are disallowed and the 76.4 disallowed FTEs for the 100 positions yet to be approved. The adjustment is calculated as shown in the tables below:

Table 29

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Capitalization Adjustment for 28.2 FTEs			
Base Salary Capitalization (53.97%)	$52,850		
Benefits Loader (46.2%)	$24,417	28.2	$688,561
NUSCO Adjustments			
Capitalization Adjustment for 4.9 FTEs			
Base Salary Capitalization (53.97%)	$47,104		
Benefits Loader (46.2%)	$21,762	4.9	$106,634
Total Disallowed Benefits Capitalization		33.1	**$795,185**

Table 30

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Capitalization Adjustment for 68 FTEs			
Base Salary Capitalization (53.97%)	$52,850		
Benefits Loader (46.2%)	$24,417	68.0	$1,660,356
NUSCO Adjustments			
Capitalization Adjustment for 8.4 FTEs			
Base Salary Capitalization (53.97%)	$47,104		
Benefits Loader (46.2%)	$21,762	8.4	$ 182,801
Total Disallowed Benefits Capitalization		76.4	**$1,843,157**

i. Summary of Adjustments to Payroll Items

Following is a table summarizing both the expense and capitalization disallowance adjustments made to payroll, payroll taxes and benefits.

Table 31

ADJUSTMENTS	EXPENSE	CAPITALIZED
Payroll	$4,870,480	$5,710,619
Payroll Taxes	$413,968	$485,390
Benefits	$2,250,146	$2,638,342
Totals	**$7,534,594**	**$8,834,351**

j. Capitalized Expense Related Items - Depreciation

Based on discussions in Section II.C.2.i, Summary of Adjustments to Payroll Items and Section II.C.3.e, 401(k) and K-Vantage, the Authority reduces plant-in-service by $8,834,351 for capitalized payroll related expenses and by $185,595 for capitalized 401(k) expense and as a result, reduces depreciation expense. Using the composite depreciation rate of 2.56%, the Authority reduces depreciation expense by $230,911 [($8,834,351 + $185,595) *.0256].

3. Retirement Expense

a. Background

CL&P has a defined benefit pension plan that covers the majority of its existing employees. However, in 2006, CL&P closed entry to its defined pension benefit plan to newly hired non-bargaining employees. Effective January 1, 2006, the Company introduced a new enhanced 401(k)-based benefit called the K-Vantage Program for all new non-union hires and allowed existing employees to opt out with their pension frozen into the new benefit program. All new employees participate in the K-Vantage benefit instead of the defined benefit plan. Peloquin PFT, p. 13. For certain officers, CL&P offers a Supplemental Executive Retirement Plan (SERP) and Non-SERP plans, which are unqualified plans based on IRS rules. The Company offers retiree health care benefits for all retired employees.

a. Pensions

The pension expense is calculated on the basis of the accounting rules set forth in Accounting Standards Codification 715-30 (ASC 715-30). Response to Interrogatory FI-27. The pension expense is based on the following elements, which in total equal net periodic benefit cost.

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

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

CL&P requested the following for pension expense in its Application:

Table 32

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$47,213,000	($21,544,000)	$25,670,000

Application, Schedules C-3.27 and WPC-3.27d.

The above request was revised, due to a change in an actuarial assumption, to the following:

Table 33

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$47,213,000	($19,477,000)	$27,736,000

Late Filed Exhibit No. 3, Revised Schedule C-3.27.

CL&P's pension expense is a product of actuarial studies that determine the Company's liability to each pension plan participant, and include assumptions on salary increases, discount rate, and expected long-term rate of return on assets. The Company's actuary calculated actual pension expense to be $47,213,000 in the Test Year ended December 31, 2013, and projected expense of $27,736,000 in the Rate

Year ended 2015. The decrease in pension expense between the Test Year and the Rate Year of $19,477,000 is due to the amortization of net investment gains from 2010 through 2013, and an increase in the discount rate as calculated by the Company's actuary for the Rate Year. CL&P Brief, p. 41.

b. Other Post Retirement Employee Benefits

The Other Post Retirement Employee Benefits (OPEB) expense is calculated on the basis of the accounting rules set forth in Accounting Standards Codification 715-60 (ASC 715-60). Response to Interrogatory FI-15. This statement focuses principally on health care benefits, where the employer promises to provide health benefits after an employee retires. These benefits are grouped together under the name OPEB and the expense is calculated with one additional assumption from pensions which is the healthcare cost trend rate. This represents the expected annual rates of change in the cost of health care benefits currently provided by the post-retirement health care benefit plan.

CL&P requested the following for OPEB expense in its rate application:

Table 34

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$7,771,000	($3,829,000)	$3,942,000

Application, Schedules C-3.27 and WPC-3.27g.

The above request was revised, due to a change in an actuarial assumption, to the following:

Table 35

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$7,771,000	($3,710,000)	$4,061,000

Late Filed Exhibit No. 3, Revised Schedule C-3.27.

CL&P has been pro-active in controlling the growth of retiree healthcare costs through capping the Company's health care subsidies and changing plan designs for both pre-65 retirees and post-65 Medicare eligible retirees. Specifics are that for employees that have retired after 1991, the portion of the cost for medical coverage that is paid for by CL&P is capped at $6,101 per person under age 65 and $2,166 per person over age 65. This lower cap that applies for over age 65 retirees reflects the lower cost to CL&P as a result of retiree enrollment in the federal Medicare program, which is the primary coverage to these individuals. In addition to these limits, employees retiring after 1994 are responsible for additional premium payments based on a retirement age of less than 65 or service with the Company of less than 20 years.

These plan features serve to limit future growth in the Company's retiree health care expense. The portion of post-retirement health care expense associated with capped benefits has grown to 85% as of December 31, 2013. Peloquin PFT, p. 11.

Further efforts to reduce retiree medical expenses resulted in pre-65 retirees being transitioned to the same new medical designs as offered to active employees in 2013. This produced a shift in retiree enrollment in higher cost options toward lower premium and higher deductible options. CL&P reported that this shift is a result of default enrollment in the point of plan option (PPO)-90 plan and a comprehensive communications campaign. For the Test Year, more than 75% of retirees participated in the lower cost plans. Due to this shift to variable out of pocket costs, retirees are encouraged to become more educated about lower cost options in choosing providers and treatment plans which should result in mitigating health care cost inflation. Peloquin PFT, pp. 11 and 12.

Another area CL&P has worked to lower costs is prescription drug expenses. The Company has made significant plan design changes to the prescription drug benefit for Medicare-eligible retirees. In 2013, CL&P introduced a Medicare Part D employer group waiver plan (EGWP) through its pharmacy benefits manager. Retiree participation in the EGWP provides a lower cost as a result of offsetting payments from Medicare in the form of Part D direct subsidy payments, low income subsidies, pharmacy manufacturer reimbursements, and catastrophic reinsurance payments. These payments are returned to retirees, whose subsidy from the Company is capped, through lower monthly premium costs. For grandfathered retirees that do not pay monthly premiums, these payments are an offset to CL&P's cost. In addition, in 2013 the carrier was consolidated for the Medicare supplement and in 2014, the Company updated the plan design for Medicare eligible retirees. These changes eliminate non-Medicare coverage and applies the full Medicare Part B deductible on all participants. Peloquin PFT, p. 12.

In 2007, CL&P implemented a new Post-Employment Health Reimbursement Account (HRA) program, Med-Vantage that supplements benefits offered to employees in K-Vantage. The Company deposits $1,000 annually into a tax-advantaged HRA account for each participant who is age 40 or older, which can be used for post-employment healthcare premiums or expenses. Peloquin PFT, p. 14.

The Authority notes that the Rate Year 2015 expense is $3,710,000 less than the Test Year expense. The Authority's analysis indicates that this is due to investment gains and changes in the forecasted discount rate for 2015.

c. Actuarial Assumptions

The key actuarial assumptions used in determining the Company's pension and OPEB expense are: 1) discount rate; 2) expected return on assets; 3) average wage increase; and 4) health care cost trend rate. The discount rate is used to evaluate the present value of the plan liabilities. The higher the discount rate, the lower the present value resulting in a lower pension and OPEB expense. The expected return is an assumption, not an actual return, and is a product of plan investment mix and the expected earnings on such mix. The higher the assumption, the more the plan assumes it can earn resulting in lower pension and OPEB expense. The average wage increase is the assumed increase in annual wages for all employees in the plan. The higher the wage increase assumption, the higher the pension expense. The health care cost trend rate is comprised of an initial and ultimate cost trend rates, which is an estimate of future health care costs. The higher the health care cost trend rates, the higher the OPEB costs. The health care cost trend rate applies only to the OPEB Plan and not the pension plan

i. Discount Rate

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 and OPEB plan liabilities. The Securities and Exchange Commission (SEC) requires the use of high quality bond yields to calculate the discount rate. In addition, the SEC has specified that discount rates should reflect the duration of a pension plan's liabilities. Response to Interrogatory FI-20.

The Company's actuary, Aon Hewitt (AH), used a yield curve methodology to calculate the discount rate for pension plan and OPEB plan liabilities. To develop its yield curves, AH uses hypothetical double A or greater yield curves represented by a series of annualized individual spot discount rates from 0.5 to 99 years. These spot rate curves are derived from a direct calculation of the implied forward rate curve based on the included bond cash flows. The forward rate curve is a continuous function and as such, this methodology allows the curves to be extended beyond the 30-year maturity period for which corporate bond data is generally available. This matches the IRS corporate bond yield curve methodology used for Employee Retirement Income Security Act (ERISA) funding calculations. Id.

AH used bond data and pricing information provided by Barclays Capital in constructing these yield curves. The bonds are screened to ensure that the resulting rates are consistent with relevant accounting standards and can be actually achieved by a pension or OPEB plan. Specific criteria used are as follows:

1. Each bond issue is required to have an average rating of double A when averaging all available ratings by Moody's Investor Services, Standard & Poor's and Fitch.
2. The universe of bonds includes only non-callable bonds so that the yield to maturity can actually be attained without intervening calls, puts or sinking funds.
3. To ensure marketability each constituent bond issue is required to have at least $250 million par outstanding.
4. Outlier bonds that have a yield to maturity that significantly deviates from the average yield within each maturity group are removed.

Id.

AH receives bond data, from Barclay's Bank, of approximately 6,000 bonds, which is effectively the data set underlying the Barclay's Aggregate Index minus U.S. Government and U.S Government related issuances. Approximately 1,000 bonds meet the selection criteria for inclusion in the AH curves. On a monthly basis, AH produces the "AA Only Above Median" curve using this data which is calculated from a subset of bonds representing the 50% highest yielding bond issues within each defined maturity tranche of the AA only universe. Using this yield curve methodology, a discount rate of 5.03% was developed for the pension plan and a 4.78% discount rate for the OPEB plan. Id. The Authority is familiar with the yield curve approach and finds it is an acceptable methodology to calculate a discount rate for pension and OPEB expense.

CL&P stated that it will revise the discount rate on its pension and OPEB plans based on information from its actuary AH in the third quarter of 2014. Tr. 9/5/14, pp. 1496 and 1497. The Company submitted a worksheet developed by AH showing revised 2015 pension expense projections based on AA median yield curves**.** In addition, the Company submitted a worksheet developed by Towers Watson showing revised 2015 pension and OPEB expense projections. These work sheets show that interest rates have decreased by about 20 basis points from 4.45% to 4.26%. Using the most recent discount rates, calculated by AH, as of August 31, 2014, resulted in an increase to pension expense of $4.2 million and an increase to FAS 106 expense of $0.6 million. Late Filed Exhibit No. 40.

The Company revised the discount rate to a lower discount rate, at the direction of its actuary. CL&P used a discount rate of 4.26% as an input to calculate pension expense and a discount rate of 4.07% to calculate OPEB expense. Id.; Tr. 9/24/14, p. 2509.

The Authority analyzed the actuarial inputs that are used to calculate the discount rate and finds that the Company is correct in changing its discount rate. The discount rate was revised by CL&P due to changes in market conditions. Based on its analysis, the Authority approves the discount rate of 4.26% for the pension plan and 4.07% for the OPEB plan.

ii. Expected Return on Assets

CL&P developed the expected long-term rate of return assumption of 8.25%, for both the pension and OPEB plans, using input from actuaries, consultants, and economists. Data inputs come from long-term inflation and growth statistics for the economy. In addition, CL&P's expected long-term rates of return on plan assets are based on certain target asset allocation assumptions and expected long-term rates of return on those individual target asset allocations. The following shows the target asset allocation weights and the expected returns for each asset class.

Table 36

Asset Class	Target Weight	Target Returns
Equities		
US Equity	24.0%	9.0%
Non-US Equity	10.0%	9.0%
Emerging Markets	6.0%	10.0%
Fixed Income		
Fixed Income	15.0%	5.0%
High Yield Bonds	9.0%	7.50%
Emerging Market Bonds	6.0%	7.50%
Alternatives		
Hedge Funds	11.0%	7.00%
Real Assets	9.0%	7.50%
Private Equity	10.0%	13.00%

Response to Interrogatory FI-20.

Management at CL&P constructed the rates of return by asset category. These rates of return are based on management's best judgment using publicly available information regarding historical data, adjustments based on current market conditions, as well as their own experience and expectations. Based on this, CL&P management determined 8.25% should be used as the long-term rate of return on assets for the pension and OPEB plans.

A comparison of actual returns on pension plan assets to assumed rates of return on these same assets are as follows.

Table 37

Year	Actual Pension Plan Returns	Assumed Rate of Return
2013	15.0%	8.25%
2012	13.8%	8.25%
2011	2.0%	8.25%
2010	16.8%	8.75%
2009	25.0%	8.75%
2008	-31.1%	8.75%

Response to Interrogatory FI-34.

A comparison of actual returns on OPEB plan assets to assumed rates of return on these same assets are as follows:

Table 38

Year	Union Retiree Health Returns	Assumed Rate of Return
2013	16.2%	8.25%
2012	14.5%	8.25%
2011	-3.5%	8.25%
2010	15.9%	8.75%
2009	25.8%	8.75%

Response to Interrogatory FI-19.

CL&P stated that actual returns on pension plan and OPEB assets will differ from the long term rate of return assumption as a result of short-term market fluctuations. In addition, over the last five years following the 2008 financial crisis, return on plan assets have benefited from strong equity and credit markets. The strong performance of these markets explains most of the difference between the actual returns and the assumed long-term rate of return. Id.

When questioned on the validity of the 8.25% return on plan assets and whether this return should be increased for the Rate Year, the CL&P witness stated:

> Because we outperformed recently, I'd expect future returns to be less because it kind of goes back to a norm. So if anything, those higher numbers in recent years would tend to lower future expectations for rates. . . . . Not only that, my long-term rate of return is a long-term rate that is subject to review by the SEC, our auditors and our actuaries, and we do not know of any other company that is increasing their long-term rate of return and also I don't believe that our auditors would allow us to do that. We wouldn't have any support for it. Tr. 9/5/14, pp. 1498 and 1499.

The most recent return as of June 30, 2014, is reported as approximately 5%. Tr. 9/5/14, p. 1499. The Authority notes that the financial markets are subject to wide fluctuations and, therefore, recent returns may not be the norm for the future. The Authority finds that the assumed ROR of 8.25% for the pension and OPEB plans is reasonable based on the unpredictability of future returns.

iii. Average Wage Increase

The long-term average wage increase assumption is based on current salary increases, the level of promotions, and the level of increases reflected in the union contracts. A higher average wage increase would result in greater benefits earned by plan participants and thus would increase pension expense. The Company used an average wage increase assumption of 3% in its actuarial calculations. Response to Interrogatory FI-20.

A comparison of actual salary increases to assumed salary increases is as follows:

Table 39

Report Date	Year Over Year Change Average Pay	Salary Increase Assumption
2014	3.0%	3.5%
2013	3.0%	3.5%
2012	3.0%	3.5%
2011	3.0%	4.0%
2010	2.9%	4.0%

Response to Interrogatory FI-32.

Differences between the average pay increase and the salary increase assumption occur in every year. This is because the salary rate assumption is based on a long-term future pay increases rather than a one-year period of actual experience. Tr. 9/5/14, pp. 1499 and 1500. In any given year, salary can fluctuate based on overtime and commissions paid to participants in the plan. The Authority finds the 3% salary increase assumption to be reasonable.

iv. Healthcare Cost Trend Rate

The healthcare cost trend rate is an actuarial component of the retiree health care expense. There are two assumptions composing the healthcare cost trend rate, which is the initial assumption and the ultimate assumption. The initial assumption reflects expectations of health care cost increases for retirees in the near term. These increases are based on a number of factors including publically available general industry surveys, actual experience of the Company's retiree population, and experience of other large clients with post-retirement health care plans. The ultimate assumption methodology is developed from a building block methodology. Under this building block methodology, the underlying inflation assumption is established to reflect improvements in technology and additional utilization. In addition, the assumptions used in the valuation of the initial and ultimate trend rates are evaluated against those used by other general and utilities industry companies to ensure comparability. Response to Interrogatory FI-21.

The health care trend affects a decreasing number of older CL&P grandfathered retirees with an average age of 84. The portion of the NU OPEB obligation related to grandfathered retirees is less than 15% of the total plan obligation. As a result, the ultimate trend rate has very little impact given the short period of life expectancy. The remainder of the NU OPEB plan obligation relates to either retiree life insurance or health care for non-grandfathered retirees, which are subject to an employer cost cap. These obligations are not impacted by health care trend rates. In addition, post-65 retiree medical trends have been lower than active trends historically, particularly since unit cost is tied to Medicare allowable costs for the medical component. Id.

CL&P used an initial health care cost trend rate of 6.75% with an ultimate rate of 4.50%. These were developed using the following sources:

1. The 2014 Segal Health Plan Cost Trend Survey conducted in May and June of 2013 indicates that combined medical and Rx trend rates (increase in per capita claims) from 7.6 – 8.0% for PPOs and high deductible health plans (HDHP).
2. PwC's Health Research Institute (HRI) projected a 6.5% medical cost trend for 2014.
3. Sibson Consulting quoted 2014 projected medical trends ranging from 7.9% - 8.4% with Rx trend projected at a 6.3% increase.
4. CIGNA, the third-party administrator that manages the provider network, reported a combined medical and Rx trend of 9.42% for 2014.

Response to Interrogatory OCC-188.

In addition, when asked about whether there may be differences in parts of the country in medical trend rates, the CL&P witness stated that "New England typically is a very high cost area. It's because we have excellent facilities, a lot of very good employers and comprehensive health coverage." Tr. 9/5/14, p. 1507.

The Authority analyzed the above health care trend surveys and finds that they are reasonable. The Authority also finds that the initial health care cost trend rate of 6.75% with an ultimate rate of 4.50% is in the range of reasonableness and is an acceptable actuarial assumption to calculate the cost of the Company's OPEB plan.

v. Conclusion on Pension and OPEB Expenses

The Authority approves CL&P's revised requested pension cost of $27,736,000 for the Rate Year. The Authority concludes that CL&P applied the accounting rules set forth in ASC 715-30 correctly. The Authority finds the actuarial assumptions of discount rate, rate of return on plan assets, and wage increases to be reasonable. The Authority also approves CL&P's revised requested OPEB cost of $4,061,000 for the Rate Year. CL&P applied the accounting rules set forth in ASC 715-60 correctly. Further, the actuarial assumptions of discount rate, rate of return on plan assets, and health care trend rate are reasonable.

e. 401(k) and K-Vantage

A 401(k) plan is a qualified retirement plan under the Internal Revenue Code that allows employees to save a portion of their salary for retirement on a pre-tax basis. Typically, employers match a portion of each employee's contribution with the employee choosing the investment options for the contributions. The Company has two 401(k) plans which is a traditional 401(k) plan and the other an enhanced 401(k) called K-Vantage.

Participation in the K-Vantage program over the past five years has grown steadily. By the end of 2013, approximately 30% of CL&P and NUSCO employees were participating in K-Vantage compared to less than 20% in 2009. Peloquin PFT, p. 15. As of January 2006, the Company closed entry to its defined benefit pension plan to newly hired non-union employees. As an alternative these employees participate in an enhanced defined contribution benefit called K-Vantage. Under K-Vantage, in addition to the traditional 401(k) match, the Company contributes an amount equal to a percentage of the employees covered pay into a 401(k) account. Peloquin PFT, p. 13. These contributions are based on the employee's age and amount of service which is as follows:

Table 40

Age plus Service	% of Covered Pay
Less than 40 years	2.5%
40 or more but less than 60 years	4.5%
60 or more years	6.5%

Peloquin PFT, p. 14.

The above percentages of covered pay were determined with the intent to produce the needed accrual to provide for a decent level of retirement. This is accomplished through the K-Vantage plan design such that the older an employee is, combined with increased years of service, an additional amount is added to the employee's plan. Tr. 9/5/14, p. 1525.

Non-union employees hired prior to 2006, were offered the opportunity to choose between continuing to earn benefits in the traditional defined benefit pension plan or to opt into the new K-Vantage plan. There were 2.6% of eligible CL&P employees and 7.8% of eligible NUSCO employees that elected to participate in K-Vantage. By 2009, all of the CL&P union employees had voted to participate in K-Vantage. All newly hired employees participate in the K-Vantage program. The Company reported that as is customary with defined contribution plan designs, CL&P employees bear 100% of the risk associated with their investment elections in the 401(k) and K-Vantage plans. Response to Interrogatory FI-6.

CL&P originally requested the following expense for its 401(k) plan which includes the K-Vantage expense:

Table 41

Test Year Expense 12/31/13	Pro Forma Adjustments	Test year Pro Forma	Rate Year Adjustments	Pro Forma Rate Year 2015
$4,391,000	$53,000	$4,444,000	$667,000	$5,111,000

Application, Schedules C-3.27 and WPC-3.27e.

The above request was revised due to a decrease in the NUSCO allocation to the following:

Table 42

Test Year Expense 12/31/13	Pro Forma Adjustments	Test year Pro Forma	Rate Year Adjustments	Pro Forma Rate Year 2015
$4,391,000	$53,000	$4,444,000	$543,000	$4,987,000

Late-Filed Exhibit No. 3, Revised Schedules C-3.27, WPC-3.27e.

CL&P reported that the conservation and load management employee expense was inadvertently included in allocated expenses reported for NUSCO employees. This amount was overstated by $141,000. Tr. 9/5/14, p. 1529; Response to Interrogatory OCC-190. The revised Test Year expense of $4,987,000 does not include the overstatement of $141,000.

The Authority looked for comparisons with other 401(K) programs from electric companies similar to CL&P to determine that the benefits being offered were within norms as the ratepayers fund the 401(k) plans. The Authority reviewed a detailed retirement plan benchmarking analysis prepared in April 2013 by Fidelity Investments as well as an industry benchmarking group survey that included a total of 14 like-sized utilities with revenues over $5 billion.[13] CL&P reported that the survey, last performed in 2013, shows total retirement value for new hires (which consists of 401k and K-Vantage program contributions only) ranks below median (approximately 90% of average) for the combined non-represented and union employees. Response to Interrogatory FI-5; Tr. 9/5/14, p. 1525. After analyzing both confidential studies, the Authority finds that CL&P's 401(k) and K-Vantage programs are within industry norms and reasonable.

CL&P asserted that it must attract and retain qualified employees. This is done through the benefits provided under CL&P's 401(k) Plan, which includes the K-Vantage program. Both are an important part of the total rewards program used to achieve this goal. Response to Interrogatory FI-7; Peloquin PFT, p. 3.

The OCC provided an adjustment to the 401(k) expense due to a payroll adjustment it made. The OCC stated that it employed the participation rate and average cost used by CL&P in its filing. The OCC calculated an adjustment of $132,000 on CL&P and for NUSCO, an adjustment of $129,000, for the Rate Year. The total 401 (k) adjustment, therefore, is $261,000 ($132,000 + $129,000). Schultz PFT, p. 18, Exhibit L&A-1, C-4; OCC Brief, p. 53.

CL&P took exception to the OCC's 401(k) adjustment. The Company stated that the OCC's methodology was based on a simplistic average. It does not account for the fact that CL&P's 401(k) plan costs are increasing as all new employees participate in this plan, rather than the defined benefit pension plan, which was closed to new employees as of January 2006. In addition, CL&P asserted that the OCC failed to recognize that the change in 401(k) expense is not linear based on historical data headcount or participation data. Future costs will be proportionally higher with each new employee due to the K-Vantage contribution (2.5%, 4.5% or 6.5%, based on age and years of service), which does not apply to employees who participate in the defined benefit pension plan. CL&P Reply Brief, p. 51.

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[13] These studies were deemed to be proprietary and confidential.

The Authority recognizes how important qualified employees are to the overall goal of serving ratepayers for the Company. Given this, the Authority finds that the 401(k) and K-Vantage plans are useful in attracting and retaining qualified employees, which is a benefit to ratepayers. The Authority approves the Company's 401(k) and K-Vantage plans. However, for the Rate Year of 2015, the Authority finds an adjustment to the $4,987,000 401(k) expense is necessary due to the PURA's adjustment to payroll of $10,581,100 ($4,870,480 + $5,710,619) See, Section II.C.2.i Summary of Adjustments to Payroll Items, Table 31.

To adjust the 401(k) expense based on the Authority's adjusted payroll, the PURA used CL&P's methodology. Based on eligibility requirements and employee participation in the 401(k) and K-Vantage Plans, the Company reported that its contribution percentage can range anywhere from 0% to 6.5%. Therefore, an average contribution rate of 3.25% (6.50%/2) is used as a proxy. Response to Interrogatory FI-119.

The Authority calculated the adjustment to the 401(k) expense as follows:

Table 43

Description	Amount	Calculation
Change in Payroll	($10,581,100)	
Company Average Contribution to Employees 401(k) Plans	3.25%	
Change in 401 (k) Expense (pre capitalized basis)	($343,886)	($10,581,100) * 3.25%
Amount Capitalized	($185,595)	($343,886) * 53.97%
Net Change in CL&P's 401 (k) Expense	($158,291)	($343,886) – ($185,595)

Based on the above calculation, the Authority approves a 401(k) expense of $4,828,709 ($4,987,000-$158,291).

f. Supplemental Executive Retirement Plan

A SERP, which is a non-qualified plan, provides executives with a supplemental retirement benefit in addition to the benefit provided under the qualified plan. CL&P reported that it is a common company practice to provide executives with a benefit that makes them whole for the limits on pensionable earnings that the IRS imposes on qualified pension plans. The objective is for executives to receive a pension that is similar to nonexecutives' pensions relative to their pay. Response to Interrogatory FI-44. CL&P reported that there are 34 current employees eligible for SERP benefits when they retire. There are 51 retired employees and/or spouses currently collecting SERP benefits. There will be no new participants in the SERP because CL&P no longer offers a defined benefit pension plan to new employees. The SERP complies with section 409A of the IRS Code. Responses to Interrogatories FI-43, FI-45, FI-46, and FI-48.

In its Application, the Company requested the following for SERP anticipated expenditures.

Table 44

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$1,680,000	$359,000	$2,039,000

Application, Schedules C-3.27 and WPC-3.27f.

CL&P stated that the Rate Year adjustment of $359,000 is due to pre-capital adjustment for NUSCO, which included allocated NSTAR costs in the rate year expense. This adjustment was partially offset by the discount rate which increased by 79 basis points from the Test Year to the Rate Year from 4.24% to 5.03%. Response to Interrogatory FI-169. The Company did not change its requested SERP expense based on a decrease in the discount rate for the rate year of 2015, which would have meant an increase in the SERP expense. Tr. 9/24/14, pp. 2509 and 2510.

The OCC opposed the Company's SERP expense in its rate case. The OCC defined SERP "as an additional retirement plan, provided to a select few employees, to increase their retirement compensation beyond what the IRS allows in a qualified plan." Schultz PFT, p. 45. The OCC's reasoning to exclude the SERP expense is based on the points cited below:

1. The SERP is available to only those employees that are already highly compensated. Therefore these highly compensated employees move even farther ahead of most of their fellow employees.
2. Employees that receive SERP benefits are already members of CL&P's regular retirement plan.
3. The SERP costs are for employees that are retired and therefore no longer providing service to ratepayers.

Id.

The OCC argued that in the 2009 CL&P Rate Case, the Authority allowed the SERP expense but with two caveats. The first was that the Authority would not authorize recovery from ratepayers of any SERP expense for employees hired after January 1, 2006. Secondly, the Authority recognized that SERP expense should not increase in the future since the SERP benefits are existing costs for the majority of those retired or inactive employees hired prior to 2006. Schultz PFT, p. 46.

The OCC's analysis shows that the SERP expense has increased significantly from the 2009 CL&P Rate Case in which CL&P included SERP costs of $1,282,000 in the first rate year and $1,277,000 in the second rate year. In the instant proceeding, the Company has $1,680,000 in the Test Year with a further increase of $359,000 in the Rate Year. The OCC argued that for an expense that should not have increased, the "jump" from $1,277,000 in the 2009 CL&P Rate Case to $2,039,000 is egregious. Schultz PFT, p. 47.

The OCC recommended a SERP adjustment to remove the entire $2,039,000 from the Rate Year. The OCC believes that this adjustment is consistent with the Authority's ruling in the Decision dated June 30, 2009 in Docket No. 08-12-06, Application of Connecticut Natural Gas Corporation for a Rate Increase. In that Decision, the Authority disallowed all costs related to both the Energy East Corporation SERP and the Excess Plan. However, if the Authority were to allow a portion of the SERP expense, the OCC recommended the removal of costs above $1,277,000, as the 2009 CL&P Rate Case stated that costs should not increase, which would be a reduction of $762,000 ($2,039,000 - $1,277,000). Id. The OCC stated that it is not recommending that the SERP be discontinued, but that CL&P's shareholders, not the ratepayers, pay for the costs. OCC Brief, p. 76.

The OCC also recommended that in conjunction with the removal of SERP costs, the offset to rate base for the SERP reserve, net of accumulated deferred income taxes, be removed, which would increase rate base by $2.128 million. The OCC made this adjustment but noted that only a portion of the net reserve be adjusted since ratepayers have funded the cost and are entitled to be credited for advancing those funds. Schultz PFT, pp. 47 and 48, Exhibit L&A-1, Schedule C-7; OCC Brief, p. 77.

The AG asserted that the Authority reject CL&P's proposal to collect any SERP expense from ratepayers, which would result in a reduction in revenue requirements of $2.0 million. The AG cited the Authority's June 30, 2009 Decision in Docket No. 08-12-06 and the Decision dated July 17, 2009 in Docket No. 08-12-07 Application of The Southern Connecticut Gas Company for a Rate Increase, where the Authority disallowed SERP expense based on the poor economy. AG Brief, pp. 17 and 18.

CL&P advocated that the SERP expense benefits ratepayers since it is necessary for the Company to offer a compensation and benefit package that correctly compensates executives with particular experience, skills and qualifications. These executives have a range of employment opportunities due to their skill levels that carry with them a certain level of compensation and benefits. As such, it becomes necessary for CL&P to offer SERP benefits to these individuals to attract them to the Company. These executives hold positions with a relatively substantial amount of responsibility and manage the work of many other employees. Hiring qualified executives is important to customers since these individuals' decisions affect a range of matters pertaining directly to the cost and quality of utility service provided to customers. Response to Interrogatory FI-49.

CL&P stated that the Authority consistently has allowed recovery of its SERP expense recognizing that the costs are "common practice among companies with qualified defined benefit pension plans." 2009 CL&P Rate Case Decision, pp. 64 and 65. In addition, CL&P cited the January 22, 2014 Decision Docket No. 13-06-08, finding that SERP expense "is an appropriate expense of doing business." CL&P Brief, pp. 49 and 50.

CL&P took exception to the OCC and AG argument to disallow SERP costs. The Company stated that the OCC and AG recommendation to disallow CL&P's costs for the SERP conflicts with established PURA precedent and the 2009 CL&P Rate Case Decision, which allowed recovery of these costs. The Company notes that while the

OCC and AG argues that the disallowance of SERP costs was supported by the June 30, 2009 Decision in Docket No. 08-12-07, CL&P asserts that they neglected to mention that the SERP ruling in that Decision was overturned by the January 2014 Decision in Docket No. 13-06-08, which allowed recovery of SERP costs. Tr. 9/5/14, pp. 2039 and 2040. In addition, the Company argued that the OCC's argument is flawed when requesting a cap on the recovery of SERP costs at $1,277,000 based on language in the 2009 CL&P Rate Case Decision. CL&P Reply Brief, pp. 50 and 51.

The Authority analyzed the SERP actuarial statements and finds them to be acceptable. Protected Response to Interrogatory FI-47. The SERP expense is driven by the actuarial discount rate. The Company testified that the change in the discount rate affected the SERP as it did pension and OPEB expense; however, the Company did not reflect the change in the discount rate as an increase in the SERP expense. The Company indicated that it does not update the SERP expense as frequently as the pension and OPEB expense. Tr. 9/24/14, p. 2509.

The Authority notes that the OCC's witness acknowledged that the Decision language on which he relied did not refer to cost changes that could occur due to active employees covered by the SERP. Tr. 9/5/14, pp. 2035 and 2036. The witness asserted that the SERP is for employees no longer providing service to the Company. However, during cross-examination, he admitted that the plan also includes active employees and that costs could change from year to year due to changes in the number of active employees. Tr. 9/5/14, pp. 2035 and 2036, 2039. The Authority determines that the 2009 CL&P Rate Case capped the SERP expense at $1,277,000 in the second rate year and the $1,282,000 in the first rate year relates only to the number of employees entering the SERP. It does not relate to the actuarial calculation of the discount rate, which is a major component of the SERP expense. The SERP expense is capped based on the fact that no new employees after January 1, 2006, are allowed in the SERP but that expense can change based on actuarial calculations. This is evident from the language in the 2009 CL&P Rate Case, which stated the following:

> The Department understands that it has been common practice among companies with qualified defined benefit pension plans to provide executives with this additional benefit, however, with the introduction of the new enhanced 401(k) plan known as the K-Advantage Program, any officers hired after January 1, 2006 will no longer be eligible to participate in SERP. The Department recognizes that the SERP expenses should not increase in the future since the SERP benefits are existing costs for the majority of those retired or inactive employees hired prior to 2006. Therefore, the Department will allow the costs associated with the existing SERP benefits as it has in past rate cases, however, the Department will not authorize the recovery by ratepayers of any SERP expenses for those hired after January 1, 2006.

2009 CL&P Rate Case Decision, pp. 63 and 64.

The Authority finds that the SERP expense should be recoverable by the Company for the same reasons as stated in its last rate case. The SERP has been a common practice among companies with qualified defined benefit pension plans to provide executives with this additional benefit. The Authority approves the SERP expense of $2,039,000 since it is based on an actuarial calculation.

g. Non-Supplemental Executive Retirement Plan

The Non-SERP account is used to record expenses related to specially negotiated post-employment benefits, including pension enhancements not covered by the NUSCO Retirement Plan or the SERP. Such enhancements are normally provided in the hiring agreements to make up for benefits lost at previous employers by some mid-career hires or as part of a separation agreement with NU. As with SERP, Non-SERP benefits have been necessary to retain some qualified personnel and as a special retention arrangement. Tr. 9/5/14, pp. 1533 and 1534.

The Authority finds that this retention of employees benefits ratepayers since it produces a well-run company. Currently, there are 60 current or former CL&P and NUSCO employees whose expense is recorded in the Non-SERP account. Response to Interrogatory FI-122. CL&P has provided a Non-SERP benefit to one employee that was hired after January 1, 2006. This Non-SERP benefit included separation benefits as part of the individual's employment agreement and continuation of certain health benefits. CL&P recorded no expense amount included in the Rate Year for any of the Non-SERP costs associated with this individual. Response to Interrogatory FI-123.

The Non-SERP is a non-contributory plan. The benefit payments that are made to participants are first contributed from CL&P to the trust and then the funds are immediately disbursed to participants. Response to Interrogatory FI-121. There were no NUSCO employees participating in the Non-SERP hired after January 1, 2006, and therefore, the Non-SERP expense does not reflect any changes allocated to CL&P from NUSCO. Response to Interrogatory FI-124. In its Application, the Company requested the following to reimburse for Non-SERP anticipated expenditures.

Table 45

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$1,203,000	($300,000)	$903,000

Application, Schedules C-3.27 and WPC-3.27g.

The Company did not change its requested Non-SERP expense in the Rate Year despite changes in the discount rate. Tr. 9/24/14, pp. 2509 and 2510.

The OCC opposed the Company including its Non-SERP expense of $903,000 in its rate case. This expense is comprised of $230,000 of CL&P expense and $673,000 of NUSCO allocated costs. Schultz PFT, p. 48. The OCC recommended the removal of the entire Non-SERP expense of $903,000. However, the OCC is not recommending that Non-SERP benefits be discontinued but that these costs be borne by shareholders. Schultz PFT, p. 50. The OCC defined Non-SERP as additional pension plans that go beyond the Company's regular retirement plan and the SERP as well. The Non-SERP expense relates to individually negotiated post-employment benefit agreements.

Schultz PFT, p. 48; OCC Brief, p. 77. The OCC argued that it is not appropriate for ratepayers to be responsible for this Non-SERP retirement package expense since it is beyond what most of CL&P's employees receive and beyond what most ratepayers receive, if they do in fact have retirement packages at all. Schultz PFT, p. 49.

The OCC noted that there is only one active employee and 60 retirees from CL&P and NUSCO receiving Non-SERP benefits, which is a reason ratepayers should not be responsible for these costs. Since the majority of the Non-SERP expense relates to former employees, it is obvious that ratepayers are not receiving current benefits from these costs. Id. The OCC also recommended that, as part of the adjustment to remove Non-SERP costs, CL&P's reserve offset to rate base, net of accumulated deferred income taxes, be removed. This would result in an increase to rate base of $406,000. The OCC made this adjustment and suggested that an argument can be made to keep the reserve as an offset to rate base because ratepayers have funded this expense and as such, should be credited for that funding. Schultz PFT, p. 50.

CL&P claimed that the Authority previously approved Non-SERP expenses since it is a benefit to employees that are a "common practice among companies with qualified defined benefit pension plans" as stated in the 2009 CL&P Rate Case Decision, pp. 64 and 65; CL&P Brief, pp. 41 and 42.

The Authority, in the 2009 CL&P Rate Case, stated the following:

> As with SERP benefit costs, Non-SERP benefits currently exist for those employees hired prior to January 1, 2006 and were part of the hiring agreements to originally retain those employees. The Department understands that this Non-SERP plan is a form of a post-employment or pension enhancement benefit, so it is only logical that the majority of these employees have since retired or become inactive. The Department does not find it fair to terminate recovery of an existing benefit that has been allowed recovery in the past.

2009 CL&P Rate Case Decision, p. 65.

The Authority also allowed the Non-SERP benefit in the Company's rate case in the Decision dated January 28, 2008, in Docket No. 07-07-01, Application of CL&P to Amend Rate Schedules.

The Authority analyzed the actuarial statements on the Non-SERP in the response to Protected Interrogatory FI-9 and finds them to be acceptable. The Non-SERP expense is driven by the actuarial discount rate. The Company testified that the change in the discount rate affected the Non-SERP as it did the pension and OPEB expense; however, the Company did not reflect the change in the discount rate as an increase in the Non-SERP expense. The Company indicated that it does not update the Non-SERP expense periodically throughout the year as is the practice for the pension and OPEB expense. Tr. 9/24/14, p. 2509. The Authority approves CL&P's Non-SERP cost of $903,000 since it is an ongoing expense and should be recoverable by the Company.

h. Allocations to CL&P from Subsidiaries on Retirement Benefits

Allocations from NUSCO are made through direct charges to the operating company that benefitted from the charge whenever possible. When costs cannot be identified as being provided to one specific company or business segment, or when direct charging is not otherwise feasible, cost allocation methodologies are used. Late Filed Exhibit No. 36. These methodologies vary with the business unit, department and cost control center. The allocation of costs for NUSCO employees is based on the NUSCO employees' total payroll, both directly charged and allocated through the use of the NUSCO charging account unit (CAU) 99 allocation rate budgeted for each year. This is referred to as the 9C allocation for the Test Year and rate C7 for the Rate Year. Responses to Interrogatories FI-152, FI-153, FI-154, FI-155, and FI-156.

The Authority approves the allocation of pension, OPEB, SERP and Non-SERP costs for NUSCO employees to CL&P based on the Authority's review of the calculations of the 9C allocation for the Test Year and rate C7 for the Rate Year. The Company's allocation methodology, for retirement benefits, is consistent with cost allocation methodologies used in prior rate cases. However, the NUSCO 401(k) cost allocated to CL&P was changed due to changes on NUSCO payroll allocated to CL&P.

Northeast Nuclear Energy Company (NNECO) is a subsidiary of NU and was the agent for Northeast Utilities system companies as well as other New England utilities in operating and maintaining the Millstone Nuclear Generation facilities. NNECO pension and OPEB expenses are allocated to CL&P based on CL&P's 81% ownership of NU's share of the Millstone units prior to their sale. This is based on the 2009 CL&P Rate Case Decision which stated that, "[t]he Department concurs with CL&P's 81% allocation of the NNECO pension costs, and finds them properly recovered in CL&P's total pension and OPEB expense." 2009 CL&P Rate Case Decision, p. 61.

The Authority approves the allocations to CL&P from NNECO for pension and OPEB expenses since this was the intention in the Authority's Decision in Docket No. 99-09-12, Application of The Connecticut Light and Power Company and The United Illuminating Company for Approval of Their Millstone Nuclear Generation Assets Divestiture Plans. In the subsequent Millstone purchase and sale agreement, the Authority required CL&P to be responsible for the NNECO pension and employee benefit costs with CL&P's share calculated at 81% of the pension and OPEB costs.

i. Capitalization

CL&P capitalized a portion of its retirement benefits expense into rate base. To the extent that employees are doing capital work, a portion of their benefits and pension costs are capitalized along with their direct labor costs. The Company indicated that the amount of pension expense that is capitalized is based on the payroll that is capitalized. The actual capitalization amounts recorded on the Company's books reflect an allocation of employee benefits, payroll taxes and insurance to expense and capital consistent with how payroll was distributed and recorded in the Test Year. Responses to Interrogatories FI-8, FI-99, FI-103, FI-110, FI-111, and FI-118. The Authority reviewed the Company's capitalization calculations and made certain adjustments See Section II.D.3.c Capitalized Expense Related Items.

j. Consultant/Actuarial Fees

CL&P requested $310,000 for consulting/actuarial fees on Schedule C-3.27 for both the Test Year and Rate Year. This is broken down as follows:

Table 46

Vendor Name	Description	($000's)
AON/Hewitt and Associates	Actuarial Services for the Pension Plans	$149
Towers Watson/Perrin	Actuarial Services for the OPEB Plans/ Benefit Consulting Services	$602
Fiondella, Milone, & Lasaracina LLP	Consulting Services/ Benefit Audits	$230
	Total NUSCO Billing	$981
	Total Percentage Allocated to CL&P Distribution	31.55%
	Total Amount Allocated to CL&P Distribution (Schedule 3.27)	$310

Response to Interrogatory FI-51.

The history of this expense is shown by the following:

Table 47

Description	2008	2009	2010	2011	2012
Actuarial Services for the Pension Plans	$91,000	$86,000	$124,000	$66,000	$123,000
Actuarial Services for the OPEB Plans/ Benefit Consulting	$591,000	$455,000	$472,000	$320,000	$238,000
Consulting Services/ Benefit Audits	$64,000	$64,000	$63,000	$70,000	$33,000
Total CL&P Distribution Expense	$746,000	$605,000	$659,000	$456,000	$394,000

Response to Interrogatory FI-151.

The actuarial and benefit consultant expenses are for costs allocated from NUSCO based on different allocator rate codes. CL&P determined that the 31.55% should be a blended rate derived from the 99 allocator rates, and not reflect the other allocators used to allocate costs in the Test Year. CL&P provided its calculation showing how the 31.55% was derived along with a calculation by individual rate code that is more indicative of how these costs were actually allocated in the Test Year.

Response to Interrogatory FI-50. The Authority analyzed the calculation and finds it is correctly done and appropriate.

The Authority does not have an issue with this expense since it has been trending downward. Based on the Authority's experience and judgment, $310,000 seems reasonable and hereby approves CL&P's $310,000 request for actuarial/consulting expenses.

4. Rate Case Expense

The Company requested $1.5 million for rate case expenses associated with the current proceeding, which would be amortized over a seven-year period. Schedule WP C-3.34, p. 3. This cost is approximately $1.3 million more than the rate case expense of $211,000 in the Company's previous rate case. The $1.5 million includes $100,000 for an ROE witness, $350,000 for a depreciation witness, $500,000 for legal services, $300,000 for the OCC's consultants, $100,000 for other external costs and $150,000 for incremental costs. Response to Interrogatory OCC-169, p. 1.

The OCC initially recommended a reduction to rate case expense of $560,000 and an annual amortization expense of $80,000. The OCC stated that ratepayers should only be responsible for prudently incurred costs and these costs are excessive. The OCC recommended that the ROE witness costs be reduced by $60,000, the depreciation witness costs reduced by $200,000, legal fees reduced by $250,000 and the OCC fees reduced by $50,000. OCC Brief, p. 74. The OCC stated there is nothing to demonstrate that the Company produced a more thorough or informative application as a result of this dramatic increase in rate case expense. Id. The OCC also claimed that throughout this docket, the Company has repeatedly failed to meaningfully respond to relevant discovery and that CL&P failed or refused to provide its cost of service study, evidence requested regarding incentive compensation, approval of capital expenditures and system resiliency spending among other items. Id.

Subsequently, the OCC recommended that the entire rate case expense be disallowed. OCC Reply Brief, p. 9. The OCC reiterated that CL&P repeatedly denied it access to documents requested in discovery. Id. CL&P then attempted to use some of the documents that it failed to provide to impeach the very witnesses who had requested those documents and that this type of gamesmanship should not be tolerated. Id.

The AG did not address the rate case expense specifically. Rather, it stated that the Authority should make the adjustments proposed by the OCC. AG Reply Brief, p. 11. The Company did not address the issue of rate case expense in either its brief or its reply brief.

The Authority considers the requested rate case expense to be unjustified. The projected expense for the Rate Year is an increase of 611% [($1,500,000-$211,000/$211,000] over the 2009 CL&P Rate Case. The Authority disallows $510,000 of the requested $1.5 million as follows: the ROE witness costs should be reduced by $60,000; the depreciation witness costs reduced by $200,000; and the legal fees reduced by $250,000. The allowed costs of $990,000 ($1,500,000 - $510,000) provide for a substantial increase when compared to the 2009 CL&P Rate Case.

The amortization period for the allowed costs of $990,000 will be four years rather than the seven years requested by the Company. The Authority determines that the seven-year amortization is excessive, considering the Company will be filing another rate case in 2017. Moreover, in its last rate case, the Company recovered the $211,000 rate case expense in one year. Typically, the Authority has allowed amortization periods for rate case expense from three-five years. As a result, the annual amortization expense for rate case expenses increases to $248,000 per year from the $214,000 proposed by the Company.

5. Residual O&M

Residual operation and maintenance (O&M) expense represents the portion of Test Year expenses that CL&P specifically did not analyze based on the size of the dollar amounts involved. Mahoney PFT, p. 44. The Authority typically allows utilities a residual O&M expense category since, without this adjustment, a utility would not be made whole for increases in its O&M expenses not adjusted for elsewhere.

Specific analysis of CL&P's original residual O&M request shows total Test Year O&M expenses, for the Test Year ended December 31, 2013, of $381,729,000. From these total Test Year O&M expenses, CL&P determined $2,513,000 to be Test Year residual O&M expenses. CL&P originally requested a Test Year pro forma adjustment of $1,005,000 which provides for a rate year residual O&M expense request of $3,518,000 ($2,513,000 + $1,005,000). Schedule WPC-3.31. CL&P revised its residual O&M expense request due to an accounting error that was discovered during this proceeding. The Test Year expense of $2,513,000 remained the same. A Test Year pro forma adjustment was made of $2,122,000 for a rate year pro forma expense of $4,635,000 [$2,513,000 + $2,122,000]. Response to Revised Interrogatory FI-40; Late Filed Exhibit No. 3; Revised Schedule C-3.31; Revised Schedule WPC-3.31.

The Company reported that the residual O&M expenses shown on Schedule C-3.31 generally exclude all significant fixed and contractual expenses. Almost all fixed and contractual expenses are material in nature and therefore would be captured in a specific C schedule. Response to Interrogatory FI-36. CL&P reported that Test Year total operating expenses were charged to over 500 accounts and sub-accounts. For purposes of this proceeding, CL&P employed the following steps to ascertain the most material expenses and specific adjustment to those:

1. For CL&P Distribution and NUSCO, costs allocated to CL&P Distribution Test Year expenses were broken down into cost control center (CCC) levels by direct costs.
2. CL&P then analyzed activities and sub activities to determine the different groupings of costs that would be presented on specific C Schedules for the Test Year.
3. CL&P analyzed these activities and sub activities to determine the nature of the expense, identify significant changes that affected the Test Year, and to estimate the rate year level of expense. This analysis further refined the

categorizing of common expenses for rate case schedules of various expenses such as insurance, telecommunications, depreciation, etc.

4. Expenses determined to be unrelated to the major categories of expenses or immaterial on a stand-alone basis then became a residual O&M expense.
5. CL&P continued to revisit various expense adjustments as needed to ensure that the residual amount was at a level that was considered reasonable given the amount of Test Year expenses and representative of a Rate Year level.

Response to Interrogatory FI-39.

During cross-examination the Company witness outlined the accounting process to ensure that the residual expenses are not included in other C schedules expense accounts. Tr. 9/24/14, pp. 2470 and 2471.

In its original filing, the Company made pro forma adjustments of $1,005,000 to the residual O&M expenses which are detailed in the following:

1. In March 2013, CL&P made an accounting adjustment correction of $1.442 million for storm costs that were not properly coded. This correction was made in the Company's test year in Account No. 593.
2. In April 2013, the State of Connecticut reimbursed CL&P $2.553 million for an overpayment of the State Economic Recovery Reduction Bonds. The Company removed this credit from the test year since it is a one-time credit adjustment in Account No. 930.
3. In December 2013, CL&P recorded $106,000 in payments in error. In January 2014, these payments were corrected.

Response to Interrogatory FI-40; Mahoney PFT, p. 44.

The Company, upon further review of its residual O&M expenses, stated that it found an error in its accounting. The pro forma adjustment of $1.442 million was done in error in the Test Year. Response to Revised Interrogatory FI-40. In addition, to the net credit of $1.442 million, CL&P found an offsetting debit, which resulted in no impact to the Test Year ended December 31, 2013. As such, the Company now indicated it should not have adjusted its residual O&M expenses by $1.422 million in its original filing. Revised Response to Interrogatory FI-114.

The accounting entries for the derivation of the $1.442 million, for storm expenses, are as follows:

Table 48

Month	Account No.	$ Amount	Description
March 2013	59306	1,441,500	Transfer to Reserve
March 2013	59306	(2,576,300)	True-up of Deferred Storm Balance
March 2013	59306	(2,039,000)	True-up of Deferred Storm Balance
March 2013	59306	108,300	True-up of Deferred Storm Balance
March 2013	59306	246,200	True-up of Deferred Storm Balance
March 2013	59306	2,819,300	True-up of Deferred Storm Balance
Total		$1,441,500	

Revised Response to Interrogatory FI-114, Attachment 1.

The journal entry for the $1,441,500 is as follows:

Table 49

Account No.	Account Description	Debit	Credit
59306	Overhead lines, distribution and maintenance (OH Distr Mntc A)	$1,441,500	
182SU	Contra – 182ST		$1,441,500
Total		$1,441,500	$1,441,500

Revised Response to Interrogatory FI-114, Attachment 1, p. 2.

The purpose of the above journal entry was to record the reserve for incremental deferred costs related to true-ups to the five deferred storms recorded in March 2013. Revised Response to Interrogatory FI-114, Attachment 1, p. 2; Tr. 9/5/14, p. 1461.

The derivation of the net total of the adjustment for the State Economic Recovery Reduction Bonds is as follows:

Table 50

Date	Account No.	Amount	Description
April 2013	93099	($2,553,000)	Reverse Reserve on CL&P Etc. - 04/13
December 2013	90800	$74,000	CL&P Corporate Relations Advertising Account (Corp Rel Acct)
December 2013	90800	$1,000	CL&P Corp Rel Acct
December 2013	90800	$26,000	CL&P Corp Rel Acct
December 2013	90800	$4,000	CL&P Corp Rel Acct
December 2013	90800	$1,000	CL&P Corp Rel Acct
Total		($2,447,000)	CL&P Corp Rel Acct

Revised Response to Interrogatory FI-40, Attachment 1, p. 1.

When questioned why the residual O&M expense request increased from its original application, the Company witness stated that it was due to a credit of ($2.477) million in residual O&M for the economic recovery bonds as a result of over payment by the state of these bonds. The credit came back from the State of Connecticut to CL&P

and as such the Company needed to remove that credit. CL&P took the Test Year amount and increased it by ($2.477) million. Tr. 9/24/14, pp. 2490 and 2491.

The Authority recognizes the revision of CL&P's journal entries resulted in an increase in residual O&M expense. After analyzing CL&P's revised journal entries, the Authority finds the journal entries to be correct.

CL&P's request of residual O&M expense does not reflect an inflation factor. It did not use an inflation factor to determine its residual O&M expense for the Rate Year based on the 2009 CL&P Rate Case Decision. This Decision allowed CL&P to recover Test Year expenses only. Response to Interrogatory FI-39.

In addition, since this is the first rate case filed approximately two years after its merger with NSTAR, it has not included an inflation factor on residual O&M expenses due to merger-related savings. It is the Company's expectation that merger related savings would be achieved within the first five years following the merger, which was reflected in the net benefit analysis at the time. As such, the exclusion of an inflation factor in this five–year time period is consistent with the expectations from the merger. Response to Interrogatory FI-117.

CL&P discovered several accounts that were included in residual O&M expenses that should not have been:

Table 51

FERC Account No.	Account Name	Amount
90500	Miscellaneous Customer Account Expense	$143,167
921105	Office Expense Building	$63,819
Total		$206,986

Late Filed Exhibit No. 39.

The Company also reported that $106,000 was incorrectly charged to CL&P. In the Company's analysis of the Test Year residual O&M expenses, it was discovered that these costs were for the low income special needs program payable to the Boathouse Group in December 2013. These costs should have been recorded to the Systems Benefit Charge (SBC) and CL&P corrected the accounting in January 2014. An analysis of bank records shows the breakdown of these costs as follows:

Table 52

$ Amount	Payment Reference No.
780.98	038147500000
4,269.33	138147500000
26,032.50	256747500000
929.88	338147500000
73,909.90	828147500000
$105,922.59	

Response to Interrogatory FI-147.

CL&P removed these accounts totaling $312,909 ($206,986 + $105,923) from the Test Year residual O&M expenses. The Authority agrees that these accounts should be excluded from the residual O&M.

The Authority examined the Company's residual O&M expenses for certain accounts that historically should not be included as a residual O&M expense. CL&P's witness stated that these expenses (i.e., non-industry dues and memberships, scholarships, charitable contributions and expenses for holiday parties) have been excluded from the residual O&M expenses. Tr. 9/5/14, pp. 1475 – 1478. The Authority's analysis indicates that these expenses are not included in the residual O&M.

The summary of changes the Company made to their original residual O&M expense request is as follows:

1. A decrease of $119,000 for officer's expenses included in the Company's Test Year.
2. Removal of a pro-forma adjustment for $1.442 million that was inadvertently adjusted. At the time of the Company's filing, it was unaware of an offsetting credit that was recorded in the Test Year as well.
3. A decrease of $207,000 for miscellaneous costs included in the Company's Test Year.

Late Filed Exhibit No. 3.

The Authority analyzed changes to the residual O&M expense of a Test Year pro forma adjustment amount of $2.121 million. These changes include a decrease of $119,000 in officer's expenses and a decrease of $207,000 in miscellaneous costs. The Authority approves these changes as filed in Late Filed Exhibit No. 3. The Authority examined the group of accounts totaling $4,635,000 for the pro forma rate year. The Authority's analysis focused on the contents of each individual account, whether the expenses were adjusted elsewhere in the Application, and whether these expenses would be recurring. The Authority finds that all the accounts that represent the residual O&M expenses of $4,635,000 are approved as a residual O&M expense. CL&P has excluded various accounts from the residual O&M expenses and are not in the total of the $4,635,000 residual O&M. Based on the Company's adjustments, the

Authority has no further adjustments to the revised residual O&M expense of $4,635,000.

6. Board of Directors Expense

The Company included $583,000 in its Application for the Board of Directors (BOD) expense. CL&P stated that its share of the Rate Year BOD expense is a legitimate business expense that should be recovered in rates. CL&P Reply Brief, p. 63.

The OCC recommended that the BOD expense be reduced by 75% because the role of the Board of Directors is to protect the interests of the Company's shareholders and ratepayers receive little, if any, benefit from this expense. OCC Brief, p. 78. The OCC noted that the January 22, 2014 Decision in Docket No. 13-06-08:

> …that the same 75/25 sharing of this expense between shareholders and ratepayers is appropriate and consistent with recent Board of Director's expense adjustments made in Decisions issued by this Authority.

The OCC stated that the Company provided BOD meeting minutes that were redacted to the point where the vast majority of text had been blackened out and that the BOD's activities were not transparent or open to the Company's customers and regulators. For this reason, the OCC recommended that the entire costs for the BOD be charged to shareholders as a below-the-line cost and removed from revenue requirements. Id.

The Authority finds that the main objective of the BOD is to protect the interest of the Company's investors or shareowners. Ratepayers may indirectly benefit from the activities of the BOD; however, ratepayers are not the focus of the BOD decisions. Consistent with the determinations in previous Decisions regarding BOD expense and Directors' and Officers' Liability Insurance (DOL) expense, the Authority allows only 25% of BOD costs in rates. Hence, the allowed BOD costs are $145,750 ($583,000 x 25%) and the disallowed costs are $437,250 ($583,000 - $145,750).

7. Directors' and Officers' Liability Insurance

CL&P requested $467,000 for DOL insurance expense. The Company stated that DOL is a legitimate business expense of publicly traded corporations because it protects directors and officers from lawsuits brought by shareholders, including unmeritous and frivolous lawsuits. CL&P Reply Brief, p. 61. Also, no one would serve on a board of directors of a publicly traded corporation without such insurance. Id. Furthermore, CL&P stated that the OCC failed to identify a single publicly traded corporation that does not purchase DOL insurance for its directors and officers and for that and the other stated reasons, the Authority should reject the OCC's requested reduction. Id.

The OCC agreed that DOL protects the officers of the Company from lawsuits brought against them by shareholders that arise as a result of decisions that they make while performing their duties. Therefore, the shareholders, who receive the payout, are the primary beneficiaries of this insurance. Ratepayers receive very little of the benefit and should not be responsible for all of the costs. OCC Brief, p. 75. The OCC noted that the Company failed to recognize that many legitimate expenses (e.g., image building advertisements, lobbying expenses) are not recoverable. Id.

The OCC recommended the disallowance of the entire expense of $467,000. However, if the Authority determines that the costs should be shared, the OCC recommended a 75/25 split between shareholders and ratepayers respectively, a reduction of $350,000. Id., p. 76. The OCC also stated that this adjustment is consistent with the Decision in Docket No. 13-06-08. Id.

The AG indicated that the Authority should reject CL&P's request to have ratepayers fund 100% of the Company's DOL insurance and, consistent with the Authority precedent, allow no more than 25% of this cost be allocated to ratepayers. AG Brief, p. 16.

The Authority finds no convincing reason to deviate from its previous treatment of DOL insurance. Consistent with the determinations in previous Decisions regarding BOD expense and DOL expense, the Authority will allow only 25% of DOL costs in rates. Therefore, $116,750 of DOL expense will be funded by ratepayers ($467,000 x 25%). This results in a DOL insurance expense decrease of $350,250 ($467,000 x 75%).

8. Healthcare Expense

The Company originally requested an increase of $4.5 million related to employee healthcare benefits expense for a total requested amount of $22.3 million for the Rate Year. Schedule C-3.27. During the proceeding, the Company revised the requested increase to $4.21 million for a revised total of $22.0 million. Schedule WPC-3.27a-Revised. The reduction in the expense is a result of an increase in the capitalization portion of healthcare benefits.

The Company stated that the increase to healthcare insurance expense is necessary to recover the normal escalation in healthcare costs based on industry data, and is consistent with the trend adjustment allowed in CL&P's last rate case. CL&P Brief, p. 37. The Company claimed that the increase is less than would have occurred without the redesign and marketing effort of employee benefit programs that was undertaken following the merger of NU and NSTAR. Id. The Company further stated that the increase was determined in collaboration with Strategic Benefit Advisors (NU's health and welfare employee benefits advisor), CIGNA healthcare (NU's health plan partner) and other trend survey data. Id., p. 38. The Company uses a self-funded program design and the escalation rate experienced between 2013 and 2014, and anticipated between 2014 and 2015 reflects growth in the cost of medical care and prescriptions (healthcare inflation) and the added cost of compliance with the Affordable Care Act. Id.

The OCC asserted that CL&P simply escalated the Test Year amount in its determination of healthcare costs and that this approach is incorrect because the Company has a self-funded plan and healthcare costs are claims driven. OCC Reply

Brief, p. 5. The OCC further stated that the Company claims that 2013 measures was a one-time cost savings are disingenuous, considering the CL&P witness agreed that the increase in employee contributions that took effect in 2013 would continue and that the CL&P escalation of 13.85% ignores the savings achieved through increased employee cost sharing. Id. Additionally, the OCC claimed that the Company's reference to this escalation being supported by a collaborative effort is also disingenuous. Specifically, considering the fact that CL&P acknowledged the three industry expert studies provided in response to OCC-188 were generic and not CL&P specific, and that the CIGNA documentation was not included. Id.

The OCC expressed concern that the documents supposedly relied upon by the Company in estimating its healthcare cost in the Application are dated subsequent to when the Late Filed Exhibit was requested at the September 8, 2014 hearing. Id., p. 6. The OCC stated that this "evidence" in support of the Application, developed after the fact, should be rejected. Id. The OCC initially recommended a reduction in healthcare expense of $3.3 million based upon an average historical increase per employee and the recommended FTE count. Id. The OCC revised its recommended adjustment to a reduction of $3.014 million to the Company's requested health care cost of $22.002 million, as a result of its revision to the FTE count for payroll and the changes made by the Company in Late Filed Exhibit No. 3. Id.

The AG did not address healthcare costs specifically, but it supported many of the other adjustments requested by the OCC to CL&P's rate request. AG Brief, p. 23.

CL&P stated that the OCC's recommended disallowance of $3.3 million is based on a skewed analysis and that it rejects industry data as well as expert guidance provided to the Company by its health and welfare employee benefits advisor. CL&P Reply Brief, p. 48. Moreover, the Company asserted that the OCC's witness calculated an average annual increase of just 6.64%, which is well below the Company's actual experience and medical trend rates for 2014 and 2015. Id. Lastly, the Company indicated that its trend increases of 7.75% in 2014 and 8% in 2015 were developed based on a minimum of four sources of information to which it applied industry-accepted underwriting guidelines and its own claim experience. Id.

Based on the evidence the Company provided, the Authority accepts the Company's proposed healthcare costs increases of 7.75% for 2014 and 8% for 2015. The Authority reduces the total employee benefits expense by $2.25 million based on its reduction of 109.5 FTEs as discussed in the Payroll section of this Decision.

9. Employee Incentive

CL&P's Test Year non-executive incentive compensation expense was $7.8 million. Application, Schedule C-3.28. The total non-executive incentive compensation expense requested for the Rate Year is $10.38 million. Id. The Company excluded executive incentive compensation expense of $8.7 million from the Application and is not seeking its recovery. Judge PFT, p. 11; Application, Schedule C-3.29. The Company stated that it limited the rate year costs to the variable compensation paid to operations and staff employees up to the director levels, whose goals and performance metrics under the post-merger program promote reliability, service quality and higher levels of customer service, among other improvements. CL&P Brief, p. 35. Also, its variable pay program is designed to drive performance improvements and operational excellence through the use of detailed metrics that may be applied across positions within the same, or across all job scopes. CL&P Brief, p. 34.

The OCC recommended disallowing the entire non-executive incentive compensation expense of $10.38 million for the Rate Year. OCC Brief, p. 60. The OCC stated that the inclusion of a portion of incentive compensation in above-the-line expenses paid for by ratepayers is appropriate only if the plan actually provides incentive to improve performance. OCC Brief, p. 56. The OCC stated that the Company's effort to emphasize how the plan focuses on customer goals as justification for the appropriateness of the cost is simply a "smoke screen." Schultz PFT, p. 22; OCC Reply Brief, p. 7. The OCC noted that the overall financial trigger to when a payout can be made is earnings per share and all incentive funding is based on an NU financial metric. The fact that the net income goal is the primary goal while customer service-related goals are of less importance, should be taken into account in determining the funding level, if any, that should be made by ratepayers. Id. In addition, the OCC stated that CL&P did not provide sufficient necessary metrics to establish that its incentive plan is indeed effective. The information that was provided strongly suggests otherwise. The OCC also claimed that the Company did not provide details of goals and results nor did it provide any evidence that goals have been raised. Id., p. 60.

The AG recommended that the Authority eliminate the entire $10.38 million from the Company's proposed revenue requirements and from rates. AG Brief, p. 17. The AG stated that CL&P's proposed incentive plans are generally designed to incent and achieve goals, such as profit levels, that benefit the Company's shareholders, not its ratepayers. Thus, ratepayers should not be forced to fund incentive plans that benefit only the Company, especially when so many Connecticut ratepayers are in difficult economic circumstances. Id. In addition, the AG stated that the Company's incentive program does not appear to be structured to provide any "incentive." Rather the Company's "incentive" plan appears to be a base compensation measure under another name therefore, ratepayers should not be forced to pay "incentive" compensation that is neither at risk nor designed to benefit the ratepayers. Id.

The Authority recognizes the importance of incentivizing employees to achieve higher standards of customer service and other goals. The Authority also acknowledges the fact that the Company did not provide compelling evidence illustrating the metrics under which incentive compensation would be achieved. The evidence the Company presented indicates that over the past 6 years, 99.7% of eligible employees received incentive compensation. Response to Interrogatory OCC-101. This suggests that the Company's incentive compensation plan is more an extension of its base compensation plan than a true incentive compensation plan.

The Company stated in its Written Exceptions that its new variable pay program is designed to drive performance improvements and operational excellence through the use of detailed metrics and therefore the Authority should allow the total requested non-executive incentive compensation of $10.38 million.

The OCC in its Written Exceptions maintains that the Company failed to provide sufficient evidence to support its claim that it has changed its incentive compensation metrics to improve performance and to focus on customer goals. Further, the OCC stated that the existing plan does not provide a true incentive for employees to achieve higher standards of customer service and other goal. OCC Written Exceptions, pp. 37 and 38.

The Authority finds that the Company's evidence in this proceeding is minimal at best. The metrics provided for incentive compensation were for one employee and one type of position. Response to Interrogatory OCC-375. The Company claimed that more emphasis is placed on customer service and customer goals. Lazor PFT, p. 23. It fails to acknowledge that its incentive compensation metrics dealing with SAIDI and CAIDI are more a function of the increase in capital expenditures on system hardening and resiliency and less a function of employees' actions.

The Authority finds that incentive compensation expenses should not be borne solely by the ratepayers. The costs should be shared by both ratepayers and shareholders. Therefore, based on an analysis of the evidence presented in the instant proceeding and consistent with its recent Decision dated September 24, 2013 in Docket No. 13-02-20, Application of Aquarion Water Company of Connecticut to Amend Its Rates and 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 the Authority disallows 50% of the total requested non-executive employee compensation for a total disallowance of $5.19 million.

10. Public Liability Expense

The Company included $4,765,000 of public liability expense for the rate year. The Test Year public liability expense was $1,955,000. The initial proposed rate year expense is an increase of $2,810,000 ($4,765,000 - $1,955,000) over the Test Year. Subsequently, in Late Filed Exhibit No. 63, the Company revised its public liability expense downward to $3,972,438 based on updated report from its actuary. Reply Brief, p. 57.

The OCC initially recommended a reduction of $2,112,400 to the public liability expense. This is the difference between the requested amount of $4,765,000 and the average of public liability expense for the years 2009-2013 of $2,652,600. OCC Brief, p. 79. The OCC later revised its recommendation based on the Company's adjustment in Late Filed Exhibit No. 63. The OCC's revised recommendation was a reduction of $752,585. This is the difference between the Company's revised requested amount of $3,972,438 and the 5-year average of $2,652,600 multiplied by the revised allocation to O&M of 57.05%. OCC Reply Brief, p. 9.

CL&P stated that its Rate Year expense is supported by an actuary that calculated the expense level based on the most recent information available about the Company's public liability losses and exposures. CL&P Reply Brief, p. 57. The Company contended that the OCC's recommendation is not supported by an actuary and that it is based on an unsupported opinion that CL&P's level of expense in the Rate

Year should merely be an average of the expense it incurred over the past six years. Id., p. 58

Based on the updated actuarial information presented by the Company in Late Filed Exhibit No. 63, the Authority determines that the requested amount of $3,972,438 is reasonable and therefore no adjustment to the public liability expense is made.

11. Facilities Rent Expense

CL&P reported $9.527 million as the rent expense for the Test Year and proposed $8.726 million for the Rate Year. The internal rent expenses are $7.18 million for the Test Year and $6.499 million for the Rate Year. The external rent expenses are $2.348 million for the Test Year and $2.226 million for the Rate Year. The $802,000 total proforma adjustment consists of reductions of $680,000 for internal and $122,000 for external rent expenses. The Company indicated that the $680,000 reduction to the internal rent expense is to remove $623,000 associated with property at 56 Prospect Street in Hartford and $57,000 associated with the closure of facilities through consolidation. Similarly, the $122,000 proforma adjustment for external rent expense is due to the closings of facilities through consolidation. Schedules C.3.19 and WP C-3.19; Mahoney PFT, p. 39.

a. NSTAR Corporate Office

As part of the total external rent expense proposed for the Rate Year, CL&P included $203,269 as its portion of the rent expense for the NSTAR Corporate office in Boston, Massachusetts. In accordance with the determination in Docket No. 09-12-05, CL&P did not include $622,939 representing its allocated amount for the 56 Prospect Street, Hartford Corporate Office. Response to Interrogatory AC-85 Attachment 1, p. 1.

Concurrent with its determination regarding the Hartford Corporate Office, the Authority opines that the NSTAR Corporate office should not negatively impact costs recoverable from CL&P's ratepayers. The Authority finds that CL&P failed to support the need for the allocated Boston corporate office space. As such, CL&P's ratepayers should not be responsible for the additional corporate office rent cost resulting from the NU//NSTAR merger. Such mergers should create cost savings from operation and management synergies and not increased operating costs for the regulated entities within the new holding company. Therefore, the Authority will reduce the Company's proposed external rent expense by $203,269.

b. NUSCO Internal Rent Expense

For facilities under the management of Rocky River Realty (RRR), the NU real estate subsidiary, internal rent expense consists of such costs as interest, depreciation, property tax and equity return expenses. CL&P indicated that the total internal RRR rents are allocated based on Test Year budgeted total payroll costs for NUSCO's employees. The Company testified that charge accounting unit (CAU) 99 allocation rates are used for direct and allocated RRR's rent expense. Response to Interrogatory AC-85, Attachment 1, pp. 1-5.

For purposes of this proceeding, the Authority focuses its analysis concerning the total internal RRR rent allocated to CL&P distribution on amounts from the Berlin Campus; 3333 Berlin Turnpike Building; and Windsor Customer Service (Windsor CS) facilities (together, RRR Facilities). For the Berlin Campus, the total rent expense for the Test Year was $8,578,534, of which $4,047,520 was allocated to CL&P. Response to Interrogatory AC-85, Attachment 1, p. 2. For the 3333 Berlin Turnpike Buildings, the total rent expense for the Test Year was $1,290,971, of which $710,109 was allocated to CL&P. Id., p. 4. For the Windsor CS facility, the total rent expense for the Test Year was $3,818,745, of which $1,651,607 was allocated to CL&P. Id., p. 5.

The internal rent expenses for the RRR Facilities are allocated in stages. The first stage involves allocation based on the total square footages occupied by the NU operating companies and by NUSCO. The second stage involves the apportionment of the total operating companies' and NUSCO's portions of the total rent amounts to the operating companies. The Company stated that the allocation factors for cost control centers (CCC) 048, 06F and 121 are used to allocate the total operating companies' portions of the total rent expenses for the RRR Facilities to the operating companies. The CCC 141 factors are used to allocate NUSCO's portion of the total rent expense to the operating companies. Response to Interrogatory AC-85, Attachment 1, pp. 1-5; Late Filed Exhibit No. 75, Attachment 3. Based on the CCC 141 allocation, 43.25% was used to allocate NUSCO's portion of total rent expense for the RRR Facilities to CL&P distribution and this percentage was shown on the work paper for CCC 1NR. Id.; Late Filed Exhibit No. 74; Response to Interrogatory AC-85, Attachment 1, pp.1-5; Schedule G-2.16 Attachment, p. 873.

Based on the following analysis, the level internal rent expense allocated to CL&P distribution as its share of the NUSCO's portion of total rent expense is overstated and the calculation of this allocation factor is flawed.

i. Equity Return

The return on equity (ROE) used to calculate the equity return costs included in the total rent expense for each of the RRR Facilities is 9.92%. Late Filed Exhibit No. 75 Attachment 1, p. 6. Ratepayers should not pay cost of capital to the Company's affiliates in an amount above the ROE allowed for CL&P in this proceeding. The equity return costs included in the total rent expense should reflect CL&P's allowed ROE in the instant proceeding. For the Berlin Campus, the Company calculated total rent expense of $8,578,534, which includes total equity cost of $3,996,782. Late Filed Exhibit No. 74, Attachment 1, p. 2. For the 3333 Berlin Turnpike Buildings, the Company calculated total rent expense of $1,290,971, which includes total equity cost of $602,726. Id., p. 4. For the Windsor facilities, the Company calculated total rent expense of $3,818,745. This amount is 99% of the total rent expense for Windsor CS because 1% was attributed to the Connecticut Valley Exchange (CONVEX). The total equity cost for Windsor CS is $1,800,458. However, only $1,782,453 ($1,800,458 x 99%) was included in the total rent expense allocable to CL&P. Id., p. 5.

Based on the allowed ROE herein, the Authority determines that the equity return costs to be included in the total rent expenses for the Berlin Campus is $3,694,606 ($3,996,782 / 9.92% x 9.17%); for the 3333 Berlin Turnpike Buildings is $557,157

($602,726 / 9.92% x 9.17%); and for the Windsor CS is $1,647,691 ($1,782,453 / 9.92% x 9.17%). Therefore, the Authority will reduce equity return costs included in the total facility rent expense by $302,176 ($3,996,782 - $3,694,606) for the Berlin Campus; $45,569 ($602,726 - $557,157) for the 3333 Berlin Turnpike Buildings; and $134,762 ($1,782,453 - $1,647,691) for the Windsor CS facilities. Consequently, the total rent expenses subject to direct and indirect allocations are $8,276,358 ($8,578,534 - $302,176) for the Berlin Campus, $1,245,402 ($1,290,971 - $45,569) for the 3333 Berlin Turnpike Buildings, and $3,683,983 ($3,818,745 - $134,762) for the Windsor CS facilities.

ii. NUSCO'S Allocation to CL&P

The Company stated that the NSTAR shared service company has been merged into NUSCO effective January 1, 2014. CL&P is now allocated costs from the former NSTAR service company and, similarly, NUSCO costs that were formerly allocated to CL&P and other NU affiliates are now allocated to NSTAR operating companies consistent with cost causation principles. Furthermore, the post-merger NUSCO reviewed its allocations to all the operating company affiliates, and that the actual cost allocation factors have changed. However, the overall allocation of service company costs has not generally caused a change to the amounts allocated to CL&P from the new NUSCO. Mahoney PFT, p. 49.

The Authority concludes that the 43.25% used to allocate NUSCO's portion of the total RRR facilities rent expense to CL&P distribution is excessive and based on an allocation factor that is without any causal effect on CL&P's use of these facilities. The Authority reviewed the 2013 Annual Report for Centralized Service Companies (Form No. 60) that NUSCO filed with the Federal Energy Regulatory Commission (FERC). Response to Interrogatory AC-20, Attachment 3. The report shows that approximately $59.874 million of the $468.84 million was billed to NSTAR Gas and Electric. The CL&P portion of the 2013 total shared cost was $252.358 million. Id., p. 307. Also, the report indicated that costs for facilities floor space should be allocated based on the projected square footage occupied. Id., Note Page 402.1. Furthermore, in the 2009 CL&P Rate Case Decision, the Company was directed to continue determining facility rent expense for CL&P based on the square footage directly charged or allocated to it, unless it could show a change in the amount of square footage needed by the distribution segment. 2009 CL&P Rate Case Decision, p. 40.

For the instant proceeding, the Company continues to use the 9C allocator that is based on NUSCO's employee labor costs and not on square footage to allocate internal rent expense to CL&P. According to the Company, the CCC 1NR allocator mirrors 9C and is based on NUSCO budgeted labor costs and does not allocate costs to NSTAR companies. Late Filed Exhibit No. 75, Attachment 4, p. 2. The Authority determines that the 9C allocator is flawed because it is based on NU legacy costs and does not take into consideration the labor costs for the NSTAR service company, which is now merged into NUSCO. More poignant to the point that the 9C allocation is faulty is the fact that the Company reported, for allocating NUSCO's costs, CCC 048 factors that are based on square footage of the Berlin Campus using the C7 allocators. Under the C7 allocation, the total CL&P distribution allocation factor is 32.94% and NSTAR's factor is

32.53%, not zero as reported under the 9C allocation, which was based on pre-merger assumptions and non-correlating labor costs. Schedule G-2.16 Attachment, p. 218.

The Company indicated that the facilities management costs for CCC 136 are allocated using the C7 Rate Code factors. These allocators are based on the new NUSCO's budgeted labor costs for both NU and NSTAR affiliates. Further, the CL&P distribution has an allocation factor of 26.95% under the C7 formula. Schedule G-2.16 Attachment, p. 608. The Company did not provide overall allocators based on the C7 Rate Code showing the total allocated rent factors for the 3333 Berlin Turnpike Buildings and Windsor CS facilities. Therefore, the Authority determines that the C7 allocation percentage of 26.95% is more appropriate than the C9 allocation percentage of 43.25% for allocating NUSCO's portion of the total rent expenses for the 3333 Berlin Turnpike Buildings and Windsor CS facilities to CL&P distribution. The C7 allocator mirrors the 9C allocator, with the exception that it is based on the new NUSCO's budgeted labor costs, not NU legacy labor costs solely based on old NUSCO costs. In its response to inquiry as to how NUSCO's 401K costs are allocated, the Company stated that the "costs are allocated based on how NUSCO employees total payroll, both directly charged and allocated through the use of CAU 99 allocation rate, is budgeted each year. This is referred to as the 9C allocation for the Test Year and rate C7 for the projected rate year." Response to Interrogatory FI-152. For the CL&P distribution allocation, the Company indicated that the 9C percentage for the Test Year is 43.25% and the C7 percentage for the Rate Year is 26.20%. Response to Interrogatory FI-152, Attachment 1, pp. 1 and 2. However, CL&P used the 9C and not the C7 allocator to determine the proposed rent expense for the Rate Year in this proceeding.

Using the C7 allocator of 26.95% for 3333 Berlin and 43.25% Windsor CS facilities for CL&P's portion of the new NUSCO's portion of the total rent expense, the Authority calculates the allowed rent expenses for the RRR Facilities as summarized in the table below:

Table 53
Calculations of the Allowed Rent Expense for RRR Facilities

	3333 Berlin Buildings	Windsor CS Facilities
Revised Total Rent Expense	$1,245,402	$3,683,983
Allocated to Operating Companies14	$ 258,047	$ 0
Portion Allocated to CL&P Distribution15	$ 258,047	$ 0
Total Rent Allocated to NUSCO16	$ 987,355	$3,683,983
Portion Allocated to CL&P Distribution17	$ 266,092	$1,593,323
Total Portions to CL&P Distribution	$ 524,139	$1,593,323

As shown in the table above, the Authority calculates allowed rent expenses of $524,139 for the 3333 Berlin Buildings and $1,593,323 for the Windsor CS facilities. Therefore, the Authority will reduce the proposed facility rent expenses by $185,970 ($710,109 - $524,139) for 3333 Berlin Buildings and $58,230 ($1,651,553 - $1,593,323 for the Windsor CS facilities.

The Company stated that the Proposed Final Decision contains a mathematical error that understates CL&P's portion of the rent expense for the Berlin Campus by $470,655. According to the Company, the $2,726,232 rental expense apportioned to CL&P in the Proposed Final Decision, calculated by multiplying $8,276,358 by 32.94%, failed to take into consideration a charge of $934,688, the CL&P portion of rental expense for the Berlin Campus directly allocated to the operating companies by RRR. The Company stated that the correct total rental expense attributable to CL&P for the Berlin Campus is $3,196,887. CL&P Written Exceptions, pp. 46-48. Thus, according to the Company, the adjustment in the draft is overstated by $470,655 ($3,196,887 - $2,726,232). Id., p. 48.

The Company is confused with the Authority's use of an overall allocation factor of 32.94% to derive the portion of the adjusted total rental expense of $8,276,358 attributable to CL&P. The C7 allocator utilized by the Authority is a combined factor that takes into consideration both the square footages directly allocable to the operating companies and the square footages allocated to NUSCO, which are indirectly allocated to all applicable operating companies. Schedule G-2.16 Attachment, p. 218. In the Proposed Final Decision, the Authority established that NUSCO should allocate cost to CL&P based on the C7 factor of 26.20% and that NUSCO's portion of total rental expense should be allocated to CL&P based on the C7 allocator of 26.95% applicable to facilities management costs. Based on the C7 allocator of 26.95%, the Authority determined that CL&P's portion of the Berlin Campus rent allocated to NUSCO is $1,850,819 ($6,867,602 x 26.95%). Thus, the total rental expense allocable to CL&P

14 Operating Companies directly occupy 20.72% of 3333 Berlin Turnpike Buildings' and 0% of Windsor CS's total square footages. Late Filed Exhibit No. 74 Attachment 1, pp. 4 and 5,

15 100% of total square footage occupied by Operating Companies is allocated to CL&P distribution. Late Filed Exhibit No. 74 Attachment 1, p. 4,

16 NUSCO directly occupies 79.29% of 3333 Berlin Turnpike Buildings' and 100% of Windsor CS's total square footages. Late Filed Exhibit No. 74 Attachment 1, pp. 4 and 5,

17 Based on Rate C7 allocation percentage of 26.95% for 3333 Berlin and the C9 rate of 43.25% for Windsor CS Facilities.

for the Berlin Campus is $2,785,507 ($934,688 + $1,850,819). The rental expense adjustment in the Proposed Final Decision is overstated by $59,275 ($2,785,507 - $2,726,232) as compared to the Company's claim of $470,655. Consequently, the Authority disallows rent expense $1,262,013 ($4,047,520 - $2,785,507) for the Berlin Campus.

The Company also indicated the Authority made a mathematical error in the Proposed Final Decision by changing CL&P's share of the cost of the Windsor CS facilities from 43.25% to 26.94%. The 43.25% allocation factor does not allocate any portion of the cost of the Windsor facilities to NSTAR; whereas the 26.94% allocation factor allocates a portion of the Windsor facility's cost to NSTAR. According to the Company, the Windsor CS facilities do not handle any calls for NSTAR's customers; and the Westwood, Massachusetts Customer Care Facility handles calls for NSTAR's customers and does not handle any calls for CL&P's customers. Therefore, NSTAR should not pay for a portion of the Windsor Customer Care facility rent expense. According to the Company, using the allocation factor of 26.94% instead of 43.25% understated CL&P's portion of the rent expense for the Windsor CS facilities by $600,338. CL&P's Written Exceptions, pp. 48 and 49.

Based on the record, the Authority agrees that the Windsor CS facilities currently does not handle calls for NSTAR affiliated companies. As a result, the Authority agrees and recalculated the rental expense adjustment for the Windsor CS facilities as detailed in the table above. The final reduction to the proposed rental expense for the Windsor CS facility is $58,230 ($1,651,553 - $1,593,323).

The total disallowed internal rent expense for the RRR Facilities is $1,506,213 ($1,262,013 + $185,970 + $58,230). Including the disallowed external rent expense of $203,269, the total disallowed allocated facility rent expense is $1,709,482 ($1,506,213+ $203,269).

12. NUSCO Capital Funding

The Company stated that NUSCO Capital Funding expense is the money that NUSCO requires to fund certain capital investment that support shared services. That expense is shared among all NU subsidiaries using the shared capital investments. CL&P indicated that the Rate Year adjustment is due to a change in NUSCO's actual 2013 payroll capital/expense allocation. The change caused an increase to the NUSCO capital funding expense of $402,000. CL&P reported $2.701 million as the NUSCO Capital Funding expense for the Test Year and proposed $3.103 million for the Rate Year. Schedule WP C-3.16. The NUSCO Capital Funding expenses are net of the capitalized portions of $0.805 million for the Test Year and $0.424 million for the Rate Year. Id. Thus, the total NUSCO capital funding expense, prior to the adjustment for the capitalized amount, is $3.527 million for both the Test and Rate Years. Mahoney PFT, pp. 42 and 43.

The Authority opines that there is no basis to increase NUSCO capital funding expense by simply changing the capital/expense allocation applicable to the Rate Year. No evidence was presented to support the claim that a change in the payroll capitalization ratio had any correlation to CL&P's use of the shared capital investments.

The Authority concludes that the capitalization ratio should be the same for both the Test and Rate Years. Therefore, the Authority will maintain the NUSCO capital funding expense at the Test Year level of $2.701 million and disallows $402,000.

13. Storm Reserve

Catastrophic storms are those events in which CL&P incurs incremental expense in excess of $5 million. The storm reserve is currently funded through the distribution rate at the level of $3 million per year. CL&P recognizes that funding the reserve at the level necessary to address storms of the same magnitude as Storm Irene in 2011 and the October 2011 Nor'easter and Storm Sandy in 2012 would not be reasonable. The Company proposed an amount for the annual storm reserve based on storm activity during the 2010-2013 period, excluding those storms. After excluding these events, CL&P stated that the existing collection of $3 million per year to fund the reserve is insufficient because its calculation of what would have been needed to fund the storm reserve amounts to $9.035 million annually. PFT Mahoney, pp. 30-32.

CL&P proposed to utilize the storm reserve to fund $2 million per year for pre-staging costs for storms that meet specific criteria. Pre-staging costs include: securing outside line and tree crews, food and hotel support to accommodate such crews, and travel time for crews. The Company proposed to increase the annual catastrophic storm reserve funding level from its current level of $3 million to $11 million, which is a $6 million increase for incremental costs and a $2 million increase for pre-staging costs. This increase will ensure that there are reasonably sufficient funds in the reserve to mitigate the expense of future catastrophic storms and for potential storm pre-staging costs. Id., pp. 31 and 32.

To balance the interests of the Company and customers, CL&P proposed that if the storm reserve accumulates a net balance of more than $50 million, it would pay customers carrying charges at the weighted average cost of capital on the amount of the over-funding during the period of time that the over-funding situation exists. Correspondingly, during the period of time that the balance in the storm reserve falls below a net negative of $(50) million, then customers would pay carrying charges to the Company on the under-recovery during the period of time that under-recovery exists. For example, assume that the storm reserve contained a net balance of $55 million for a three-month period and decreased to $45 million due to a catastrophic storm that occurred in month four. Then the Company must pay customers carrying charges on the $5 million over-funding that existed in the storm reserve during that three-month period where the net balance of the reserve exceeded the $50 million threshold. Additionally, the Company proposed to have the ability to elect to credit to customers a portion of the positive balance held in the storm reserve exceeding the $50 million threshold when it makes adjustments to any other rate component on January 1st or July 1st through the existing administrative rate adjustment process. Id., p. 32.

The OCC recommended that the storm reserve remain at the $3 million level. The OCC based its recommendation on the fact that the Company included a $93.805 million capital expenditure request in the filing for system resiliency. It is a glaring inconsistency to include both $93.8 million for system resiliency and an increase of $8 million for the storm reserve accrual. According to the OCC, the Company is either ignoring the positive effects of the resiliency plan or assumes that the plan will be ineffective. Ratepayers should not be asked to pay for two contradictory expenses. The OCC also argued that three of the storms used by CL&P in its calculation of the reserve are also included in the Company filing for separate recovery. It is inappropriate and could be considered double dipping to use the costs being recovered elsewhere as the basis for increasing the reserve calculation. Finally, the Company requested $2 million for pre-staging costs and the OCC references Mr. Bowes testimony in Docket No. 12-06-09. Mr. Bowes stated that the Company would be allowed to seek recovery of pre-staging costs in future proceedings after they were incurred. The Decision in that docket stated that the costs would be subject to a "detailed review" including thorough documentation. As the Company does not have actual costs for review and recovery, its request in the Application is inappropriate, untimely and should be disallowed. OCC Brief, pp. 64-66.

Regarding the double counting of storms, the OCC stated that unusual storms that are allowed recovery by other means should be excluded from the reserve calculation. The OCC points out that the Company excluded the costs for Storm Irene, the October 2011 Noreaster and the 2012 Storm Sandy because they were unusual. However, the Company's Table KBB-JLM-7, used to calculate the estimated storm reserve of $9 million included the June 2011 and September 2012 storms that were approved for recovery in the Decision dated March 12, 2014 in Docket No. 13-03-23, Petition of The Connecticut Light and Power Company for Approval to Recover Its 2011-2012 Major Storm Costs (Storm Cost Recovery Decision). The table also included the 2013 storm costs deferred and included in the Company's request for recovery in the current filing. The OCC argued that this is inappropriate since the Company already has a means for recovery for the catastrophic storms, such as the Storm Cost Recovery Decision. In analyzing previous storm reserve activity, the OCC stated that the Company did not charge any costs to the storm reserve in 2008 and 2009. In 2010, costs of $14.783 million were charged to the reserve and as of September 2014, there were no charges to the 2014 reserve. If the deferred storm costs are removed from the calculation, the OCC calculated that the remaining amount charged to the reserve over 2008-2013 is $15 million. Amortized over six years, it equals $2.5 million annually and represents a reasonable level. Id.

The Company stated that the OCC is incorrect in its contention that system resiliency spending should limit the need to fund the storm reserve above current levels. CL&P's system resiliency initiatives are comprehensive system upgrade measures that will strengthen and modernize the system on a systematic basis over a period of time. The long-term impact of these upgrades will not be fully realized until there is critical mass in terms of the percent of the system completed. The existing PURA-approved five-year (2013-2017) System Resiliency Plan addresses 7% of CL&P circuits. The OCC claims the current accrual amount of $3 million "is considered generous because the effects of a system resiliency plan should actually reduce the reserve amount." However, it argued that "the Company has barely started implementing the $300 million resiliency plan." In the opinion of CL&P, the OCC cannot have it both ways. If the Authority grants CL&P's request to increase the storm reserve, it will have an opportunity in the 2017 rate case to re-evaluate the reserve funding level, specifically, to determine whether the proposed $9 million contribution level will continue to be appropriate given actual experience in the intervening time period. CL&P Reply Brief, pp. 52-53.

The Authority will first address the non pre-staging portion of the reserve request, which the Company proposed to increase from $3 million annually to $9 million annually. There is no debate that the Company has seen significant storm activity in recent history, this is well documented in the Storm Cost Recovery Decision where the Company sought recovery of $414 million for costs associated with historic weather events. Since those events, the Company has embarked on a capital spending program aimed at strengthening its distribution system. This is well documented in the Resiliency Decision.

The OCC is correct that the Company has a means for recovery of catastrophic storm expense, which would be the request for the establishment of a regulatory asset to be recovered. There is also an expectation that the capital spending that the Company is performing should have a beneficial effect on storm expense items. It is also of note that the Company is planning to file for its next rate case in two and one-half years from the time of the conclusion of this docket. In an instance where the Company incurred storm costs as it had in 2011-2012, before its next rate case, the reserve as proposed would offer little relief to ratepayers. The shortened time frame between rate cases provides an opportunity for the Authority to gauge the effectiveness of the resiliency work that the Company is performing and will provide a better measure of what a storm reserve will be going forward. The Authority will maintain the Company's annual $3 million reserve and therefore, reduces the Company's request by $6 million. The Authority also denies the Company request for a storm reserve fund with carrying charges or credits.

14. Incremental Storm Costs Included in Base Rates

The Company currently recovers $9.6 million in rates annually to offset the cost of non-catastrophic storms. These are storms in which the Company's per-storm incremental expense is less than $5 million. Costs associated with this category of incremental expense include such items as overtime, intercompany expenses for labor, materials and supplies, travel expenses and outside services including services of other utilities, electrical and tree trimming contractors. The Company does not propose any increase to the current $9.6 million that is collected annually to offset the cost of non-catastrophic storms. The Company is using an historical average for Rate Year expense purposes similar to that used by the Authority in 2009 CL&P Rate Case Decision. As reflected in Table MJM-8 below, CL&P identified the incremental storm expense of $9.6 million by taking the incremental storm expense after capitalization and transferring it to the storm reserve for 2008-2013 of $57.9 million. The total net incremental cost was then reduced by removing the low and high years (2011 and 2010, respectively) to yield a net incremental storm expense. This net incremental storm expense amount was then averaged based on the remaining costs during the four years that were selected out of this six-year period, which produced an average annual amount of approximately $9.6 million. The Company reflected the adjustment for the $9.6 million in Schedule C-3.21 along with workpapers illustrating how it derived the average.

Table 54
O&M Expense for Non-Catastrophic Storms 2008-13
($000's)

Rate Year Calculation		Historical Amounts		
2008		$	14,428	
2009			8,603	
2010			15,451	
2011			3,983	
2012			11,437	
2013			4,041	
Six Year Total			57,943	
Less: Low Year (2011)			(3,983)	
Less: High Year (2010)			(15,451)	
Adjusted Total			38,509	
4 Year Average		$	9,627	(a)
(a) Round the rate year to		$	9,600	

Workpaper C-3.21.

The OCC recommended that the Company's Test Year expense of $4.041 million be allowed in the Rate Year and that the increase of $5.559 million be rejected. The Company included a significant increase in major storm expense. The requested amount increases the expense for major storms despite the fact that the Company has included a large increase in expense for system resiliency. The OCC claimed that in ignoring the impact of the system resiliency plan, the Company is trying to have it both ways. For CL&P to justify the extensive costs of its resiliency system, it must acknowledge some positive impact on storm damage. OCC Brief, p. 68.

The Company stated that the OCC's proposal is inconsistent with the methodology of using a multi-year average, as the Authority in CL&P's last two rate cases, the 2009 CL&P Rate Case and Docket No. 07-07-01, Application of The Connecticut Light and Power Company to Amend Rate Schedules (2007 CL&P Rate Case). The OCC did not object to the use of this methodology in the 2009 CL&P Rate Case, and proposed using a multi-year average calculation in the 2007 CL&P Rate Case. Additionally, there are several instances in this case where the OCC proposed using multi-year averages to support its proposed reductions in this case; but the OCC avoids using a multi-year average here because in so doing, supports the current recovery level of $9.6 million. The OCC's sole justification in support of its substantial reduction to CL&P's current annual collection for non-catastrophic storms is its claim that the Company's proposal "ignores the increase requested in the system resiliency program." This assertion ignores the reality that the benefits of that system resiliency plan will take time to achieve. In 2017, when CL&P is expected to request the PURA to establish new distribution rates, the Company asserted that the Authority will have an opportunity to re-evaluate the non-catastrophic storm funding level to determine whether an adjustment is appropriate given actual experience in the intervening time period. CL&P Reply Brief, pp. 53 and 54.

The Authority finds that this item differs from the storm reserve in that the reserve is built into base rates and the expense is funded throughout the year through customer rates. If the amount is less than the amount included in base rates in a particular year, the Company has collected rates for an expense that it did not incur. Conversely, if the amount is more than the amount included in base rates in a particular year, the Company has not collected rates for an expense that it did incur. Therefore, it is important to set the level of incremental storm expense at an appropriate level.

As mentioned, the Company calculated the level of incremental storm expense based on historical experience from 2008-2013, with adjustments that remove the high and low amounts in that time period, 2010 and 2011. The OCC's protest to this approach is that it does not take into consideration the amount of resiliency work that is being performed on the system, which the OCC claimed should reduce storm related costs. The variation of this item over the years and the Company's smoothing of the expense by removing high and low points from its request, result in the Authority find this to be an appropriate level for this expense at this time. Experience between now and the Company's next rate case will provide additional data points for the Authority and all parties to consider at that time. Again, this item differs from the reserve as this is an item built into base rates as opposed to the reserve. The Authority therefore allows an incremental storm expense of $9,600,000.

15. Pre-Staging Costs

CL&P proposed to utilize the storm reserve to fund $2 million per year for pre-staging costs, for the purpose of securing resources in advance of catastrophic storms. Pre-staging costs include, for example, securing external line and tree crews, food and hotel support to accommodate such crews, and travel time for those crews. The Company asserted that it is necessary to recover eligible pre-staging costs because the EDCs must undertake necessary preparations to be able to comply with the Authority's storm performance standards and to restore power within the timelines stakeholders demand. CL&P noted that in 2012 and 2013, it incurred $609,000 and $1,622,000, respectively, in pre-staging costs for storms that were expected but ultimately did not occur. Mahoney PFT, pp. 31 and 32; Response to Interrogatory AC-92.

The Company also stated that pre-staging costs cannot be predicted in advance of a storm event. According to CL&P, each storm is different and they are always difficult to predict. Since resources must be pre-arranged that are located one to four days' travel time from Connecticut, financially significant issues must be made in advance of storm impact. Whether the storm materializes or not, CL&P still incurs these costs. Finally, the Company opined that there is currently no ratemaking mechanism by which it can recover pre-staging costs since they are not routinely incurred. Bowes PFT, pp. 45-48.

The OCC stated that the Company does not have actual detailed pre-staging costs available for review. Therefore, the $2 million per year expense should be disallowed as inappropriate and untimely. OCC Brief, p. 64.

The Authority strongly encouraged CL&P to devote greater efforts to pre-staging resources in anticipation of a major storm. In its Decision dated August 1, 2012 in

Docket No. 11-09-09, PURA Investigation of Public Service Companies' Response to 2011 Storms (2011 Storms Decision), the Authority stated:

> In the future, CL&P should place higher priority on taking aggressive action in anticipation of such events, including pre-staging resources and making earlier attempts to acquire resources.
>
> The Authority finds that CL&P should establish a heightened state of readiness and be able to clearly document that such a state exists. In conjunction with this expectation, the Authority will order CL&P to report on actions it has taken to establish a heightened state of readiness in anticipation of a major storm including an assessment of its own lineworkers and lineworkers from sister companies and contractors. CL&P shall also state the mutual assistance organizations to which it belongs and the resources likely available from those organizations. The Authority requires that the primary emphasis of this report focus on those resources that are likely to be available during the first 48 hours of a major storm event to assist in efforts to ensure public safety. The Authority will also order the company to demonstrate its efforts to establish a heightened state of readiness.

2011 Storms Decision, p. 51.

In its investigation into the response to Storm Sandy in 2012 that was documented in the Decision dated August 21, 2013 in Docket No. 12-11-07, PURA Investigation into the Performance of Connecticut's Electric Distribution Companies and Gas Companies in Restoring Service Following Storm Sandy, the Authority noted a number of actions that CL&P took to pre-stage resources, and concluded that the Company prepared very effectively for Storm Sandy, especially through procuring and pre-positioning supplemental lineworkers prior to the storm. Decision, pp. 16-19 and 54. This investigation confirmed the valuable role that pre-staging brings to major storm response.

The Authority previously recognized the major benefits of pre-staging resources to storm restoration and public safety. 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. The Authority finds that since it has strongly encouraged both EDCs to take actions that will require them to incur pre-staging costs, the PURA should provide surety that the costs are recoverable to lessen any financial disincentive to take those actions. The Authority concludes that the requested funding level of $2 million per year is reasonable given that costs were incurred in 2012 and 2013. As these are preparation costs for storms that never occur, the Authority will look for prudent decision-making in incurring these costs. Therefore, the Authority allows the Company to fund a reserve for pre-staging costs at the $2 million/year requested level. Unused amounts will not be accumulated for future years. At the end of each calendar year, unused pre-staging amounts should be transferred to the non pre-staging storm reserve. The Company shall separately account for storm reserve and pre-staging storm reserve amounts. 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.

16. Additional Storm Costs

The Company seeks recovery for storm costs that were not addressed in the Storm Cost Recovery Decision. These costs amount to $31.068 million and relate to the windstorm of January 31, 2013, the blizzard of February 8, 2013, and the remaining Hurricane Sandy costs that were not finalized at the time of the Storm Cost Recovery Decision. Amounts for these individual events are identified in Exhibits MJM-4 through MJM-6 of the Application.

The OCC stated that in calculating the additional level of storm costs, CL&P did not follow the capitalization policy applied by the Authority in the Storm Cost Recovery Decision because the Company argued that the treatment in that Decision was specialized. The capitalization classification changed with the Storm Cost Recovery Decision and should be followed on a going forward basis. The Company submitted a calculation that replicated the capitalization for the 2013 storms and Storm Sandy deferral using the procedure used in the Storm Cost Recovery Decision. The result is an additional $804,164 of capitalized items for the reclassification of costs associated with the 2013 storms and $7,010 for the residual Storm Sandy amount. This would reduce the amount subject to amortization by $811,174. The OCC recommended that the $31.068 million deferral requested by the Company should be reduced by $811,174 to $30.257 million. This would reduce rate base $446,000, net of deferred income taxes and it reduces amortization expense $116,000. OCC Brief, pp. 49 and 50; Late Filed Exhibit No. 51.

The Company stated that it has not adjusted the 2013 storm costs to reflect the adjustments made in the Storm Cost Recovery Decision because the determinations in that Decision were based on the unique factual circumstances of Storm Irene, the October 2011 Nor'easter and Storm Sandy, which were addressed in the Storm Cost Recovery Decision. CL&P asserted that the Storm Cost Recovery Decision did not change the Company's standard accounting practices for typical storms, nor did it establish new accounting practices for general application. As such, the Company recorded its costs related to the 2013 storms consistent with its standard accounting practices and with the treatment approved by the Authority in the past for typical storms. CL&P Response to Interrogatory AC-148.

The Authority agrees that the events contemplated in the Storm Cost Recovery Decision were based on the unique factual circumstances of those events. The Authority also finds that the Storm Cost Recovery Decision did not establish new accounting practices for general application. Going forward, the Authority will review events on a case by case basis to determine the appropriate accounting treatment to be afforded any particular event. The Authority sets a threshold amount of $20 million per event as the amount where CL&P must provide evidence that the Company's standard accounting practices are appropriate. In this Decision, the Authority approves the Company's request to recover $31.068 million related to the windstorm of January 31, 2013, the blizzard of February 8, 2013, and remaining Storm Sandy costs that were not finalized at the time of the Storm Cost Recovery Decision.

17. Troubleshooter Organization

a. The Prior Troubleshooter Organization

The Company has used troubleshooters for decades. The Company claimed that its prior troubleshooter organization (TSO) was not structured or sufficiently robust to cover the geographic area and time periods necessary to restore power to customers in the minimal time achievable for the types of trouble events that occur during off hours. The Company routinely compares its outage response performance with other utilities using a JD Power customer survey (Survey) to measure how customers view CL&P's performance in this area. The Survey indicated that the Company performed below the average of its peers in customer satisfaction for the restoration of power following non-storm-related outages. In 2013, CL&P reported its Customer Average Interruption Duration Index (CAIDI), the average time required to restore service, was 107.1 minutes compared to a better peer average of 102 minutes, and that its service was scored at 604 compared to a better peer average score of 655. CL&P Response to Interrogatory OCC-166. In addition, the Survey revealed that 89% of the surveyed utilities have a TSO devoted to outage restoration and trouble response. The Survey also indicated that 93% use one-person crews that pair up, as needed, to accomplish repair work. Tr. 8/27/14, p. 102; Bowes PFT, pp. 35 and 36.

Utilities that have good performance in responding to outages and trouble calls as measured by CAIDI and have positive customer experience as measured by the JD Power Score have a TSO that is directly connected with their system operation center (SOC). These utilities have troubleshooter crews that cover different geographic areas, but report through a centralized organization structure. The roving crews are able to cross town, district, and divisional boundaries to respond to outages and trouble calls. In addition, crews working during a shift are brought together if repair work during that shift requires additional support instead of calling in additional crews that work on a different shift to provide such support. Id.

The Company had two other major concerns with the prior TSO, the stability of the day time workforce and quality of life issues for line workers. The daily work center schedules were substantially affected by the number and frequency of instances in which line mechanics from the first shift were called out to perform emergency restoration work on the second and third shifts because there were an insufficient number of troubleshooters to respond to outages on these shifts. When this occurred, it reduced the availability and the ability of line mechanics to complete planned work and meet customer appointments during the first shift due to necessary rest time, which resulted in adjusted work schedules. The quality of life for a large number of mandatory on-call employees was affected due to the employees being unable to develop predictable family and non-work-related schedules and being forced to be on-call during the summer to ensure adequate coverage. Id., pp. 35 and 36.

CL&P's prior TSO had two classifications of line workers. The first classification were line mechanics that worked the day shift Monday through Friday and were primarily responsible for routine construction projects, maintenance of distribution lines, new service installations and, occasionally, responded to outages and trouble calls as necessary. The second classification was troubleshooters who were primarily responsible for responding to outages and trouble calls. Id., p. 34. According to CL&P, all of the troubleshooters are line workers, but not all line workers are troubleshooters. Tr. 8/27/14, p. 106. Prior to the implementation of the new TSO program, there were 49 CL&P troubleshooters covering primarily the first and second shift, seven days a week in some area work centers. Typically, there was one troubleshooter per area work center on the first and second shifts and the third shift was covered by a weekly on-call rotation. Id.

b. The New TSO

The Company reorganized its TSO in spring 2014 and it was fully implemented by June 1, 2014, to improve service levels and decrease the duration of outages on the second and third shifts and on weekends. The new TSO became centralized and expanded its troubleshooter organization of 49 FTEs by adding 119 contract line workers, 10 contract foremen and 4 contract general foremen to provide expanded coverage 24 hours a day all year. Tr. 8/27/14, p. 105; Bowes PFT, pp. 34 and 35; CL&P Response to Interrogatory AC-129.

The regular first shift, Monday through Friday, are staffed with CL&P line workers and the second and third shifts and weekends are staffed with contract line workers. The expanded TSO will provide coverage to address both small-scope and large-scope emergent work, such as outages and trouble calls. Generally, the troubleshooters are geographically disbursed across the system, but can be aggregated in teams to work together if the actual restoration project requires additional support. Under the new centralized organization, troubleshooters will be organized into three geographic areas, with supervision in each area reporting directly to a troubleshooter management team consisting of CL&P managers. Additionally, the new troubleshooter organization is no longer bound by the boundaries of the Company's area work centers or divisions. The troubleshooter managers report to the Director of System Operations, who also oversees the Company's SOC. This alignment of the new troubleshooter organization with the SOC helps the Company pursue and manage a consistent response to outages and other trouble, providing a consistent platform and set of expectations across CL&P for developing customer restoration estimates. Bowes PFT, pp. 37 and 38.

The three geographic areas of the TSO do not necessarily correspond to the Company's three new divisional boundaries because the troubleshooters are deployed in a manner that: (1) assigns them to those portions of the electric system that historically, and in the future, are more likely to sustain outages and trouble calls and not routine construction or new service work; (2) incorporates travel distance and time concerns due to varied geography and development density across the CL&P service area; and (3) incorporates varied customer density patterns. Troubleshooters will perform other routine, day-to-day work when they are not responding to outages and trouble calls such as cut-out additions and replacements, installations of animal guards, lightning arrestor change-outs, pole shifts, transformer upgrades and, during nighttime hours, street lighting repairs and flood light additions. CL&P will utilize qualified line contractors who are members of the International Brotherhood of Electrical Workers

(IBEW) labor union from a Connecticut-based line contractor. CL&P will continue to work with its existing unions to attempt to implement an internal workforce for the troubleshooter organization. Id.

The Company expected that the new TSO structure will improve customer service by reducing the off-normal working hour CAIDI by 40 minutes, which will lower CL&P's overall CAIDI by up to 15 minutes. In addition, the new troubleshooter crews will work 24/7 as their normal working hours. Also, the stability of the daytime workforce will be improved because daily schedules can be maximized with a stable resource level to increase the overall efficiency of the workforce. Schedule adherence can be maximized and the area work centers will more effectively meet customer appointments and take on more construction and system resiliency projects. CL&P indicated that hiring crews that work 24/7 will reduce the number of callouts of additional personnel and thus can help improve response rates for those instances when a callout is necessary. Lastly, the Company stated that quality of life issues for employees is expected to improve by avoiding multiple forced on-calls for weekends during the summer months, and providing weekend coverage as part of regularly-scheduled work. Id., p. 39.

c. Costs

The Company projected that the cost of the new TSO to be $10.7 million and estimated that savings from the avoidance of cost for overtime work, associated rest periods, overtime meals and their meal time costs would save $5.7 million. CL&P Response to Interrogatory OCC-167. The Company is requesting that the Authority allow an adjustment to Rate Year O&M expense of $5.0 million to cover the annual net cost of the organizational change. The Company claimed cost is warranted by the direct and substantial improvement in service quality that will result from the implementation of an industry best practice. Moreover, this cost is conservatively quantified based on the cost of internal labor to fill the additional troubleshooter positions, although the Company will be using contract resources to fill the positions for the foreseeable future. Bowes PFT, p. 41. The quantification of net cost of this new initiative is conservatively based on internal labor rates.

The greater availability of the contractor resources on-system will add to the Company's resources in larger-scale, system-wide emergencies such as storm events. These critical resources will be located in Connecticut, available to the Company, and will already be familiar with the electrical distribution system and the state's geography. As a result, the expanded TSO contractor workforce will be a valuable asset in storm response. Bowes PFT, p. 40.

d. Position of the OCC

The OCC is concerned that the Company's estimate of new TSO costs of $10 million has not been offset by costs in the test year. Schultz PFT, p. 36. The $15 million for outside services and contract labor is excessive. The OCC determined that $4.552 million was spent for overhead line maintenance and it covered the labor for 49 contract workers, which equates to approximately $92,000 per contract worker. By hiring 84 more contract workers at $92,000 per year, the contract labor costs would increase to $7.803 million. The OCC concluded that the $15 million costs for outside services and contract labor less the TSO $5 million savings in labor cost and less the $7.8 million for contract labor results in an excess estimate of TSO costs of $2.2 million and recommended that the Company's request be reduced by $2.2 million. The OCC stated that a cost benefit analysis should be performed to show that there is a benefit from the new TSO. The OCC questioned the type and level of work to be performed at night and claimed that the Company's description of work to be performed at night is not typically performed at night. Id., pp. 36 and 37.

e. Authority Conclusion on the TSO

The Authority reviewed the record and CL&P's rebuttal to the OCC's claim that the cost of the new TSO is overstated by $2.2 million. CL&P explained that the OCC incorrectly assumed that 49 troubleshooters under the former TSO were outside contractors. The 49 troubleshooters were employees of CL&P. Further, the labor cost is irrelevant with the $4.552 million spent for outside services and contractor labor that the OCC used to calculate an average contractor labor rate. WP C.310, p. 2 of 2. CL&P's estimate of contract labor in the new TSO was based on adding 90 contractors consisting of 80 line workers, 8 supervisors and 2 managers. CL&P Response to Interrogatory OCC-167. The OCC based its estimated contractor labor cost on an additional 84 contractors which understated the labor costs. Bowes Rebuttal PFT, p. 12.

The Authority accepts CL&P's explanation that associating 49 CL&P employees with the $4.55 million spent for contractor services is inaccurate. The Authority finds that the calculation of the average contactor labor cost by the OCC is not supported and rejects the OCC's claim that the new TSO cost would be $15 million. The Authority finds no justification to accept the OCC's recommended $2.2 million funding reduction for the new TSO.

Based on the reported lower restoration times experienced during the second and third shifts and for weekends at utilities using the new type TSO, the potential of increased availability of CL&P line workers having a more certain work schedule during the first shift to meet scheduled appointments and service calls, the elimination of geographic boundaries so work crews can respond to any type of outage, the opportunity to adjust the number of contract workers due to seasonal work and having additional contract work in the service territory at the start of normal and major storms. The Authority will allow CL&P's request to annually fund $5 million for the new TSO. At the time of its next annual CAIDI reliability filing in March 2015, the Company shall report the CAIDI for the second and third shifts and for weekends and the average number of contract workers staffing each work period to demonstrate the change that the new TSO had on reliability for these periods and the overall system and report the annual contractor costs of the new TSO.

In its next rate case, the Company will also be required to report the annual CAIDI and JD Power service scores for CL&P and its peer group and justify the effect that the new TSO had on these results.

18. Computer Expense

In Revised Late Filed Exhibit No. 3, the Company requested $11.187 million in computer expense for the Rate Year based on a Test Year amount of $17,250 with a pro forma adjustment reduction of $6,063 million to the Test Year amount to arrive at $11,187 million ($17,250 - $6,063 = $11,187). This is an allocated amount from NUSCO to the Company. Late Filed Exhibit 3, p. 2.

The Authority reviewed the Company's percentage changes and compared it to Schedule G-2-16 attachment to allocate NUSCO computer expense to CL&P. The Company based its request on various types of computer expenses that have various percentages of allocation to CL&P to arrive at Rate Year computer expenses of $11,187. In addition, the Authority reviewed the NUSCO allocation and accepts the Company's rate year amount of $11,187 million.

19. Facilities Maintenance

The Test Year expense for facilities maintenance was $5.990 million with a pro forma adjustment amount of ($606) for the proposed Rate Year amount of $5.384 million. Revised Late Filed Exhibit No. 3, p. 2.

The Authority reviewed the charges that comprise the facilities maintenance and finds them to be appropriate at this time. Therefore, the Authority will allow and accept the Rate Year facilities maintenance expense of amount of $5,384 million.

20. Customer Service Expense

The Company proposed $3.795 million for its Rate Year customer service expense. Late Filed Exhibit No. 3. In its Late Filed Exhibit 36, the NUSCO total amount was $1.611 million of which $1.057 million was allocated to CL&P from NUSCO. Late Filed Exhibit No. 36, p. 6. The Company subsequently reduced the Test Year amount of $3.839 million by $44 to arrive at the Rate Year amount of $3,795. ($3.839-$44)=$3795).

The Authority reviewed charges that comprise the customer service expense account and finds them to be appropriate at this time. Therefore, the Authority accepts the CL&P Rate Year amount of $3.795 million for customer service expense.

21. Conclusion on Expenses

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

Table 55

Summary of Expense Adjustments

Descriptions	Amounts ($)
Amortization Expense	34,000
Board of Directors' Fees	(437,000)
Depreciation Expense	(7,440,000)
Directors' & Officers' Liability Insurance	(350,000)
Employee Incentive Compensation	(5,190,000)
Gross Earnings Taxes	(139,000)
NUSCO Capital Funding	(402,000)
Other Employee Benefits	(2,250,000)
Payroll Expense	(4,870,000)
Payroll Taxes	(414,000)
401k	(158,000)
Property Taxes	(1,988,000)
Rent Expense	(1,709,000)
Storm Reserve Accrual	(6,000,000)
Total Expense Adjustments	**(31,313,000)**

D. TAXES

1. Gross Earnings Tax

Based on its current rates, CL&P reported Gross Earnings Tax (GET) expenses of $69.126 million for the Test Year and proposed $69.566 million for the Rate Year. Late Filed Exhibit No. 3, Schedule WPC-3.37, pp. 1 and 2. For the proposed additional revenue requirements, the Company proposed incremental GET expenses of $8.659 million for revenues from distribution operations; $1.792 million for system resiliency; and $5.186 million for regulatory storm costs. Late Filed Exhibit No. 3, Schedules A-1.0, p. 1; A-1.0 A, p. 1; and A-1.0 B, p. 1. Therefore, the total GET expense proposed for the Rate Year is $85.203 ($69.566 + $8.659 + $1.792 + $5.186) million.

As discussed in Section II.E. Gross Revenue Conversion Factor, the Authority calculated a GET Rate of 7.0606%. CL&P proposed total present base rate revenue of $983.676 million for the Rate Year. Late Filed Exhibit No. 3, Schedule WPC-3.37, p. 2. The total additional revenue requested for the Rate Year is approximately $221.098 million. Id., Schedule A-1.0. Thus, the total proposed revenue requirement subject to GET is $1,204.774 ($983.676 + $221.098) million, and the Authority determines that the GET expense on this amount is $85.065 ($1,204.774 x 7.0606%) million. As a result, the Authority reduces the GET expense proposed for the Rate Year by $139,000 ($85,203,000 - $85,065,000).

2. Interest Synchronization

The Authority adjusted the rate base amounts proposed by the Company and no change was made to the cost of long-term debt. Therefore, an interest synchronization adjustment is made to match the allowed rate base and with the income tax calculation. The rate base reduction adjustments reduces interest expense deductions for income for tax purposes and conversely increases income tax expenses. The tables in Section V. Rate Model, include adjustments to income taxes to reflect the impact of interest synchronization.

3. Municipal Property Taxes

CL&P reported property tax expense of $66.231 million for the Test Year and proposed $81.121 million for the Rate Year. Application, Schedules C.3.35, WPC-3.35A and WPC-3.35B. CL&P stated that property tax expense for the Rate Year is based on known assessed property values, updated for estimated depreciation, capital additions, retirements, and escalated mill rates. The property tax expense is amortized over the 12 months in a fiscal year beginning on July 1st. Mahoney PFT, p. 38. Furthermore, the Company indicated that its facility consolidation plan resulted in several reductions to the operating expenses for the Rate Year, including reductions to property tax expenses. Id. In its updated filing, CL&P increased its proposed property tax expense for the Rate Year to $81.435 million. Late Filed Exhibit No. 3, Schedule WPC-3.0, p. 1; WPC-3.35 A, p. 1. The revised request is to correct for a $75,000 calculation error in the Company's original filing and to reflect updates to estimated mill rates. Id. The Company total property tax expense proposed for the Rate Year equals the sum of 50% of the total actual property tax expense of $77,915,194, or $38,957,597, for the 2013 list year, plus 50% of the total estimated property tax expense of $84,382,289 or $42,191,145, for the 2014 list year. Id., Schedules WPC-3.35 A, p. 5 and WPC-3.35 B, p. 4. The total estimated property tax expense for the 2014 list year was determined by escalating the 2013 list year's personal and real estate property mill rates by 4%. Id. For tangible personal property, the Company reported a composite mill rate of 31.48 for the 2013 list year and 32.74 for the 2014 list year. Late Filed Exhibit No. 3, Schedules WPC-3.35 A, p. 5 and WPC-3.35 B, p. 4.

a. Escalation of Mill Rates

Concurrent with its previous rulings regarding mill rate escalations, the Authority concludes that the Company's proposal to escalate actual mill rates by 4% is not supported.[18] No evidence was provided in this proceeding that municipalities in the Company's service territories would, on average, increase their mill rates by 4%. The actual mill rate data available is for the 2013 list year. With the escalation removed, the Authority determines that the total estimated property tax expense for 2014 list year is $81,133,216 and for which 50% is $40,566,608 ($81,133,216 x 50%). As a result, the Authority disallows property tax expense of $1,624,537 ($42,191,145 - $40,566,608).

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[18] See the 2009 CL&P Rate Case Decision, pp. 83 and 84; and the 2007 Rate Case Decision, pp. 74 and 75.

The Company stated that neither the OCC, the AG, nor any other participant opposed its proposal to escalate the 2013 list year mill rates by 4%, which equates to the $1,624,537 municipal property tax expense disallowed in the Proposed Final Decision. CL&P stated that its estimated mill rates escalation of 4% is conservative based on actual mill rate increases of 4.26% for list years 2010-2011; 7.14% for 2011-2012; and 4.41% for 2012-2013. However, the Company agreed to settle for a smaller mill rate escalation of 2% for the Rate Year and recommended that the Authority reduce the property tax expense reduction to $812,268.50 instead of the $1,624,537 disallowed in the Proposed Final Decision. CL&P Written Exceptions, pp. 45 and 46.

The Authority maintains its determination in the Proposed Final Decision that an arbitrary escalation of municipal property mill rates is improper as it ignores other variables that may impact actual property tax expenses.

b. Projected Plant Additions and its Depreciated Value

For the 2014 list year, CL&P reported total plant additions of $233.789 million and based on its proposed composite depreciation rate of 2.56%, it calculated a related net book value of approximately $227.804 million. Late Filed Exhibit No. 3, Schedule WPC-3.35B, p. 4. Using the 70% assessment factor, CL&P calculated total assessment value of approximately $159.463 million for the 2014 list year plant additions. Id.

The Authority takes issue with both the total plant addition and the related net book value amounts that the Company used to calculate the additional property tax requested. The Authority determines that the total plant addition for calendar year 2014, which the Company used as the proxy plant addition amount for the 2014 list year, is approximately $231.456 million. Schedule B-2.0; Tr. 09/12/14, p. 2398. CL&P stated that the difference of approximately $2.333 million is due to timing differences between the cutoffs for filing property tax and the Application. Id. Nevertheless, the Company agrees that the actual timing difference amount could go in either direction of the plant additions proposed for this proceeding. Id., p. 2399. For the 2014 list year, the personal property declaration period essentially runs from October 1, 2013 through September 30, 2014. Given the fact that only nine months in 2014 falls within the 2014 list year time frame, the Authority concludes that the 2014 list year plant addition timing difference would likely result in a declared amount less than the calendar year 2014 plant additions of $231.456 million. Therefore, the Authority recognizes the calendar year 2014 plant additions of $231.456 million as an appropriate proxy for property tax additions and disallows $2.333 million of plant additions from the calculation of property tax expense for the Rate Year.

Pursuant to Conn. Gen. Stat. §12-63(b)(6), the depreciated value of tangible personal property in their first year of declaration is 95% of acquisition costs. Thus, the Authority infers that the Company's depreciation composite rate of 2.56% is not applicable for the calculation of net book value for the proposed plant additions. Thus, the net book value for calculating the assessment value is 95% of the acquisition costs for the 2014 list year plant additions

c. Capitalized Expense Related Items

Based on discussions in Section II.C.2.i. Summary of Adjustments to Payroll Items, and Section II.C.3.e. 401(k) and K-Vantage, the Authority reduces plant-in-service by $8,834,351 for capitalized payroll related expenses and by $185,595 for capitalized 401K expense. Therefore, the Authority calculated a total plant addition amount for which additional property tax expense is applicable of $222.436 ($231.456 - $8.834- $0.186) million. Based on the foregoing, the Authority determines that the assessment value for the plant additions that should be included in the 2014 list year is $147.920 ($222.436 x 95% x 70%) million. Consequently, the Authority reduces the property tax expense associated with the proposed plant additions by $363,376 ($159.463 - $147.920) million x 0.03148).

In summary, the total reduction to the Company's proposed property tax expense is $1,987,913 ($1,624,537 + $363,376).

E. Gross Revenue Conversion Factor

The Company proposed a gross revenue conversion factor (GRCF) of 1.8252 for the Rate Year. Schedules A-3.0, A-3.0 (A) and A-3.0 (B). CL&P used a GET rate of 7.072% to calculate its proposed GRCF. This GET rate was determined by dividing the Test Year's GET expense of $69.126 million by the billed distribution revenue of approximately $977.414 million. Schedule WP C-3.37, p. 1.

The Authority finds that the proposed GET rate was overstated because CL&P did not incorporate unbilled revenues into the total base revenue used for the calculation. Based on CL&P's responses in this proceeding, unbilled revenues related to distribution, conservation and load management, and renewable operations are summarized below:

Table 56

Operations	Unbilled Revenues
Distribution	$1,514,144
Conservation and Load Management (C&LM)	137,787
Renewables	(30,268)
Total Unbilled for Distribution GET Expense	$1,621,663

Response to Interrogatory AC-70 Attachment 1, p. 2.

The total revenues proposed for the Rate Year encompass all revenues, billed and unbilled. Also, the proposed revenue deficiency represents the difference between the total Test Year revenues and the proposed Rate Year revenues at present rates. The Authority disagrees with CL&P's use of only billed revenue to calculate the proposed GET rate. The appropriate total base distribution revenue for calculating the GET rate is of $979.036 ($977.414 + 1.622) million. Therefore, the Authority calculated a GET rate of 7.0606% ($69.126 / $979.036). Consequently, the Authority determined that the appropriate GRCF for the Rate Year is 1.8250.

F. Cost of Capital

1. Introduction

In determining the appropriate allowed cost of capital, Conn. Gen. Stat. §16-19e(a)(4) requires that:

> The level and structure of rates be sufficient, but not more than sufficient, to allow public service companies to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interest both existing and foreseeable.

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

The Company retained the services of a cost of capital expert, Mr. Robert Hevert, to present evidence, to provide a recommended return on equity (ROE), and to assess the reasonableness of the Company's capital structure and cost of debt. The Authority notes that the Company is proposing to use the Test Year equity ratio, instead of the forecasted capital structure supported by CL&P's witness, Mr. Robert Hevert. The capital structure is discussed in more detail below.

2. Capital Structure

a. Capital Structure

The Company proposed rates that are based on a capital structure consisting of 50.38% common equity, 2.01% preferred stock and 47.61% long-term debt. Hevert PFT, p. 56. CL&P's long-term capital structure goal is to have an approximate 52% to 48% equity to debt ratio, and to have that capital structure used for ratemaking. CL&P Response to Interrogatory FI-52. Although CL&P plans to have an actual capital structure of approximately 52%/48% equity/debt in the Rate Year ending 2015, it has not made an adjustment to the Rate Year to reflect that expectation, and has instead reflected in this case, the equity ratio that existed at the end of the Test Year, December 31, 2013. The Company indicated that in its next rate case, it will present its actual capital structure. Mahoney PFT, p. 23. The Company's proposed capital structure and its corresponding component costs are depicted in the table below.

Table 57
Proposed 2015 Average Capitalization

Class of Capital	($000) Amount	% of Total	Cost	Weighted Cost
Long-Term Debt	2,770,150	47.61%	5.45%	2.60%
Preferred Stock	116,894	2.01%	4.80%	0.10%
Common Stock	2,931,000	50.38%	10.20%	5.14%
Total	5,818,044	100.00%		7.84%

Application, Schedule D-1.0.

As determined in the 2009 CL&P Rate Case, CL&P's currently allowed capital structure is 48.35% long-term debt, 2.45% preferred stock and 49.20% equity. CL&P Response to Interrogatory FI-53. As a measure of capital structure, Mr. Hevert calculated the average capital structures for each of his proxy companies which indicated an average common equity ratio range from 46.14% to 61% on an operating company basis. Hevert PFT, p. 58; Exhibit RBH-15, p. 2. Mr. Hevert's 15-member proxy group had an average capital structure consisting of 52.95% common equity, 0.25% preferred stock and 46.80% long-term debt. Id. Based on Mr. Hevert's capitalization analysis, CL&P's proposed and target capital structures are somewhat more leveraged than those in place at the utility operating companies held within the peer group. CL&P Response to Interrogatory FI-54. In Mr. Hevert's opinion, increasing the equity ratio to approximately 52% will serve to bring the Company in line with its peers, and would improve its ability to access the capital markets, at reasonable cost rates, under a variety of capital market conditions. Hevert PFT, pp. 59 and 60.

Mr. Hevert claimed that CL&P's capital structure has less equity than other electric utility operating companies rather than their consolidated parents, which he asserts is industry practice. Hevert PFT, p. 57. The OCC's cost of capital witness, Dr. Woolridge, contends that this assertion is incorrect because Mr. Hevert excluded short-term debt and also compared the capitalization ratios of the operating subsidiaries of the proxy group companies. Woolridge PFT, pp. 16 and 17. When evaluating financial risk, short-term debt must be included in a company's capitalization because it is a senior debt claim. As an example, Dr. Woolridge shows NU's, CL&P's parent company, common equity ratio of 49.64%, including short-term debt, which comprises 8.40% of the capitalization. Woolridge PFT, Exhibit JRW-5, Panel C. If short-term debt were to be excluded, then its average quarterly common equity ratio would only be 43.2%, a significant difference in common equity ratios. Also, comparing capitalization ratios of the proxy group's operating subsidiaries is incorrect because operating companies do not have common stock outstanding; therefore, these should not be used to estimate an equity cost rate. According to Dr. Woolridge, the proper comparison is to the actual proxy group capitalizations, including short-term debt. Id.

Dr. Woolridge provided the average quarterly capitalization ratios for all the holding companies in Mr. Hevert's proxy group which averaged 5.72% short-term debt, 45.86% long-term debt, 0.26% preferred stock, and 48.16% common equity. Woolridge PFT, p. 15; Woolridge Exhibit, JRW-5, p. 2. Given the proximity of the common equity ratio of 50.38% to those of the proxy group and NU, the OCC has accepted CL&P's

proposed capital structure. Woolridge PFT, p. 16. The OCC has adopted the Company's proposed capital structure and senior capital cost rates into its analysis. Woodridge PFT, p. 3.

In allowing a cost of capital, the Authority finds it reasonable to assume the additional equity of a 50.38% equity structure in the cost of capital calculation. The Authority determines that by slightly increasing the equity ratio from 49.20%, as determined in the Company's last rate case, to 50.38% would not dramatically increase the cost of capital, but will continue to support healthy debt ratings and expand CL&P's marketablility to attract the necessary capital. Ultimately, a strong capitalization should minimize the cost of capital through lower interest rate on financings as well as increase the availability of capital itself. While CL&P is striving to reach a 52% equity capitalization by the end of 2015, the Authority finds that the proposed 50.38% equity ratio in this rate proceeding is in line with its peers and other electric utilities with similar financing requirements and business risks. CL&P will continue to maintain its capital structure by coordinating in terms of timing and amount of common dividends paid to NU and the equity infusions that it receives from NU. As such, the Authority finds that a 50.38% equity proportion is more than fully adequate and should enable the Company greater access to the capital markets and financial flexibility.

b. Cost of Long-Term Debt

The Company's proposed average long-term embedded cost of debt for the 12 months ended December 31, 2015, was estimated at 5.45%, based on the 2013 Test Year equity ratio of 50.38%. Application, Schedule D, WP D-1.2, p. 3. The long-term debt consists of 19 series of first mortgage bonds and 9 series of pollution control revenue notes (PCRBs). CL&P Response to Interrogatory OCC-249. In order to balance the proposed capital structure, CL&P expects to issue $500 million of long-term debt in 2015. Tr. 9/10/14, pp. 1758 – 1761. The estimated embedded cost of debt also includes the unamortized cost associated with refinancing the 2005 Series A bonds and to fund the anticipated redemption of the 1996 Series A PCRBs. Unamortized costs for the PCRBs will be amortized over the term of the new first mortgage bonds. CL&P's Supplemental Response to Interrogatory OCC-249-SP01.

The Authority notes that based on CL&P's Order No. 1 compliance filing for the 12 months ended June 30, 2014, 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 and/or Purchased Gas for Electric and Gas Public Service Companies, the Company lists an embedded cost of debt of 5.21%. CL&P has projected a higher embedded cost of debt of 5.45% for 2015. The OCC has accepted the proposed cost of debt into its recommendations. The Authority finds that 5.45% is a reasonable actual embedded cost of debt for CL&P as it reflects the current cost of any new planned debt issuances and refinancings.

c. Cost of Preferred Stock

The Company is expected to have $116,919 in preferred stock in its capital structure as of December 31, 2015, at a cost of 4.80%. Application, Schedule D-4.0. CL&P has 13 series of perpetual preferred stock that was issued between 1947 and

1968. Id. The Authority notes that rating agencies and investment banking firms treat preferred stock differently in that they will assign a credit to the mix of debt and equity. Based on discussions with the rating agencies, it is CL&P's understanding that equity credit for preferred stock can range from no credit to up to 50% credit. In the case of CL&P's preferred stock, Standard & Poor (S&P) considers 50% as equity and 50% as debt. CL&P Response to Interrogatory FI-57. This treatment of the Company's preferred stock has remained consistent in past rate proceedings, receiving 50% common equity credit. The 50% common equity credit assigned to CL&P's preferred stock reduces the amount of true common equity that the Company must maintain in order to achieve the same credit ratings objective. The Authority accepts the Company's proposed 4.80% costs as submitted in Schedule D-4.0.

3. Cost of Common Equity

In determining a return that is fair and reasonable while enabling the Company to operate properly and attract the necessary capital, the Authority judiciously reviewed all the testimony and evidence proffered by the witnesses in this proceeding and determines a change in CL&P's allowed return of 9.40% is warranted. The Authority finds it necessary to make various adjustments to the cost of equity data submitted in order to improve its analytical quality. These adjustments support a downward adjustment to the Company's currently allowed return. The Authority finds that the overall financial and economic indicators, business and financial risk and capital cost rates, in general, have declined since the time of CL&P's last rate proceeding. In addition, the merger of NU and NSTAR has enabled CL&P to have an even stronger financial position. The Company is obviously functioning in a relatively low interest rate environment, today, which has contributed to lower expected returns. The downward trend of approved ROEs nation-wide clearly signifies a lower cost of capital environment. Moreover, the Authority finds that the implementation of a full decoupling mechanism that helps mitigate the earnings pressure of the Company, further reduces the overall risk profile of the Company.

Therefore, in considering the arguments and analyses of the parties and intervenors, the Authority has set CL&P's ROE at 9.17**%**, and adopts such return in this proceeding. The Authority determines that such return is fair and reasonable, enabling the Company to operate properly and attract the necessary capital for capital investments. The cost of equity component, which is a measure of the investor's expected return, is discussed as follows:

a. Introduction

There are several methods commonly used to determine the appropriate cost of equity. The determination of the cost of equity in this proceeding was obtained using the discounted cash flow (DCF) method and the capital asset pricing model (CAPM) to a proxy group of companies. The DCF evaluates future cash inflows (dividends and capital gains) that investors expect to receive from a stock against the current market price investors pay for a stock. The discount rate that brings the present value of the cash flows exactly equal to the market price is the cost of equity. The Authority generally relies on the DCF analysis but also considers other methods. Accordingly, material was also presented using the risk premium CAPM by the Company's witness and the OCC. The CAPM evaluates the cost of equity by determining first an appropriate risk free rate. To this rate it adds a beta (or the degree of co-movement of the security's rate of return with the market's rate of return) times the expected equity risk premium (the amount by which investors expect the future return on equities, in general, to exceed that on the riskless asset). The following is a summary of the positions of the parties on the subject of cost of equity:

b. Company ROE Proposal

The Company's cost of equity testimony was prepared by Mr. Hevert, a financial consultant on behalf of CL&P. Mr. Hevert advocated for an allowed ROE of 10.20% from a range of 10.20% to 10.70%. Hevert PFT, pp. 2 and 3. Mr. Hevert's testimony relied on DCF model (including the Constant Growth, Quarterly Growth, and Multi-stage forms), the CAPM (including both the traditional form of the CAPM and the Empirical CAPM), and the Bond Yield Plus Risk Premium approach to develop his cost of equity results by applying to a proxy group of electric utilities. Hevert PFT, p. 3. Although Mr. Hevert did not make an explicit adjustment to his recommended ROE of 10.20% for flotation costs, Mr. Hevert modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. Hevert PFT, pp. 51 and 52; Exhibit RBH-14. Reflected in his recommended ROE of 10.20%, Mr. Hevert calculated a 14-basis point adjustment to reasonably represent flotation costs for the Company. Id. In determining where the Company's ROE falls within his range of results, Mr. Hevert also took into consideration the Company's existing and proposed Earnings Sharing Mechanism, its proposed Decoupling Mechanism and the implications of certain State policy goals included in the Comprehensive Energy Strategy. Hevert PFT, p. 4.

As CL&P's stock is not publicly traded, Mr. Hevert's initial cost of equity calculations were primarily based on a proxy group of 15 publicly traded utility companies. Hevert PFT, pp. 6 – 11. However, Mr. Hevert subsequently revised the analyses for the proxy group presented in his direct testimony based on updated data through July 31, 2014. Hevert Rebuttal Testimony, dated August 22, 2014, p. 69 and Rebuttal Exhibit RBH-11. Using this updated data resulted in one company being eliminated to form a 14-member proxy group. To determine the composition of the proxy group, Mr. Hevert began with the universe of 47 companies from Value Line's Electric Utilities Industry. Mr. Hevert then applied the following screening criteria to determine his recommended proxy group: 1) consistently pay quarterly cash dividends; 2) covered by at least two utility industry equity analysts; 3) investment grade senior unsecured bond and/or corporate credit ratings from S&P; 4) regulated operating income over the three most recently reported fiscal years comprised of at least 60% of the respective totals for that company; 5) regulated electric operating income over the three most recently reported fiscal years represent at least 90% of total regulated operating income; and 6) not known to be party to a merger, or other significant transaction as of July 31, 2014.

The Authority notes that 24 of the companies were eliminated from Value Line's Universe of Electric Utilities based on Hevert's fifth criteria of a company having at least 90% of regulated electric operating income. Response to Interrogatory FI-88. The companies included in this proxy group with their ticker symbols were American Electric Power Company (AEP), Cleco Corporation (CNL), Duke Energy Corporation (DUK), Empire District Electric Company (EDE), Great Plains Energy (GXP), Hawaiian Electric Industries (HE), IDACORP (IDA), NextEra Energy (NEE), Otter Tail Corporation (OTTR), Pinnacle West Capital Corporation (PNW), PNM Resources (POR), Southern Company (SO) and Westar Energy (WR). Prior to updating the data used for the proxy group, Mr. Hevert indicated that one of his proxy group companies, Pepco Holdings, announced the acquisition by Exelon on April 30, 2014, subsequent to the period used in the initial analyses. Hevert PFT, p. 11. Pepco Holdings was the company that was eliminated from Mr. Hevert's updated proxy group.

After selecting the 14-member proxy group, a cost of equity was calculated using a DCF method. Although Mr. Hevert recognizes the Authority places more weight on the Constant Growth DCF approach, he contests that there are a number of assumptions and constraints that may affect the reasonableness of its results. Therefore, Mr. Hevert included the Quarterly and Multi-Stage models, as well, to address those concerns. Hevert PFT, pp. 13 and 14. In theory, the standard DCF formula is based on the stock's current price reflecting the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the cost of equity as the discount rate that sets the current price equal to expected cash flows. The Constant Growth DCF model assumes: 1) a constant average annual growth rate for earnings and dividends; 2) a stable dividend payout ratio; 3) a constant price to earnings multiple; and 4) a discount rate greater than the expected growth rate. Hevert PFT, p. 14. In other words, assuming that the earnings and the dividends of a company grow at a constant rate, the DCF takes the standard form, whereas, the first term is the expected dividend yield and the second term is the expected long-term annual growth rate.

$$K = [D_o \times (1 + g) / P] + g$$

where: K = Discount rate or Investor's required ROE

D_o = Annualized dividend per share as of July 31, 2014

P = Current stock price (average 30, 90 and 180 day price)

g = Expected long-term annual growth rate (Zacks, First Call, Value Line, Sustainable Growth)

The first step in implementing the constant growth DCF model is to determine the expected dividend yield which is simply the annual dividend divided by a stock price. Hevert PFT, pp. 14 and 15. Mr. Hevert originally calculated the dividend yield based on the proxy companies' current annualized dividends and average closing stock prices over the 30, 90 and 180 trading day periods ended April 15, 2014. However, Mr. Hevert subsequently updated his analyses based on the data through July 31, 2014. Hevert Rebuttal Testimony, p. 69. Mr. Hevert adjusted the dividend yield to account for periodic growth in dividends by applying one-half of the long-term growth rate to the current dividend yield. While Mr. Hevert does not disagree with the Authority's use of Value Line as a sole source for projected dividends, he elected to use Bloomberg Professional Service as a source because it reflects the views of multiple analysts. Hevert PFT, p. 16. Mr. Hevert's original testimony calculated the average adjusted dividend yields using the 30-day, 90-day and 180-day average stock prices at 4.01%, 4.12% and 4.20%, respectively, for the period ending April 15, 2014. Hevert PFT, Exhibit RBH-1, pp. 1 – 3. As a result of using updated data through July 31, 2014, the average adjusted dividend yields using the 30-day, 90-day and 180-day average stock prices were reduced to 3.81%, 3.88% and 3.99%, respectively, for the 14-member proxy group. Hevert Rebuttal Exhibit RBH-1, pp. 1 – 3.

For the purpose of the DCF model, the next step is to develop a single growth rate component that reflects investors' growth rate expectations for the electric utilities. In order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Hevert PFT, p. 16. According to Mr. Hevert, the fundamental measure of growth is earnings because dividends are paid from earnings and book value can only increase through retained earnings or with the issuance of new equity. His findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Hevert PFT, pp. 17 and 18. Mr. Hevert used a consensus of long-term earnings growth estimates from Zacks, First Call and Value Line.

Additionally, Mr. Hevert included the sustainable growth approach to estimate a company's expected growth. The sustainable growth model is based on the theory that a firm's growth is a function of its expected earnings and the extent to which those earnings are retained and reinvested in the company. Hevert PFT, p. 18. This is calculated by the formula, g = br + sv, whereas 'b' is the expected retention ratio, 'r' is the expected return on equity, 's' is the common equity to be issued annually as new common stock and 'v' is the equity accretion rate. The 'br' portion of the formula projects growth as a function of internally generated funds. The Company stated that the 'sv' portion of the equation reflects an element of growth as the product of the growth in shares outstanding, and that portion of the market-to-book ratio that exceeds unity. As such, Mr. Hevert represents the 'sv' term as: (M/B – 1) x Common Shares Outstanding, whereas, M/B is the market-to-book ratio. Hevert PFT, p. 19; Exhibit RBH-2. As historical experience suggests that future earnings do not necessarily increase as the retention ratio increases, Mr. Hevert does not believe it is an appropriate measure of expected growth. However, recognizing that the Authority has included sustainable growth as a measure of expected growth in the DCF approach in prior proceedings, Mr. Hevert produced two sets of DCF analyses, one including sustainable growth rates and another excluding those estimates. Hevert PFT, pp. 20 and 21. Using Value Line as the source for the data, Mr. Hevert calculated an average sustainable growth rate of 4.39% for his proxy group. Rebuttal Exhibit RHB-1, pp. 1 – 3. Combining the long-term earnings growth estimates with the sustainable growth, resulted in an average growth rate of 5.28% for the 14-member proxy group. Excluding the sustainable growth rate, resulted in an average earnings growth of 5.61% for the comparable companies. Hevert Rebuttal Exhibit RHB-1, pp. 4 – 6.

For the constant growth DCF, Mr. Hevert calculated the high and low DCF results by combining the maximum and minimum EPS growth rate estimate as reported by Value Line, Zacks, First Call and sustainable growth with each company's dividend yield. Based on updated data through July 31, 2014, the constant growth DCF results, including sustainable growth, resulted in a reduced range of 7.58% to 10.95% (compared to 7.57% to 11.16% using data as of April 15, 2014). Excluding the sustainable growth, the constant growth DCF produced a range of 8.26% to 10.87% (compared to 8.24% to 11.08% as of April 15, 2014). Hevert Rebuttal Testimony, p. 70, Tables 9a and 9b; Hevert PFT, pp. 21 and 22, Tables 3a and 3b.

According to Mr. Hevert, the constant growth DCF model is limiting because it assumes dividends are paid annually, and, consequently, likely to understate the cost of equity. Hevert PFT, pp. 22 and 23. While the adjusted yield is meant to address that assumption, it does not reflect the quarterly receipt and reinvestment of dividends. For that reason, Mr. Hevert developed the quarterly growth DCF model. This model replaces the D component of the constant growth DCF model with the following equation: $D = d_1(1 + k)_{.75} + d_2(1 + k)_{.50} + d_3(1 + k)_{.25} + d_4(1+k)_0$, whereas, d_1, d_2, d_3, d_4 is the expected quarterly dividends over the coming year, and 'k' is the required ROE. To calculate the expected dividends over the coming year, Mr. Hevert obtained the last four paid quarterly dividends for each company, and multiplied them by one plus the growth rate. Again, using the closing stock prices over the 30, 90 and 180 trading days period ending July 31, 2014, the quarterly growth DCF results ranged from 7.71% to 11.20% (compared to 7.69% to 11.40%, as of April 15, 2014) including sustainable growth, and 8.41% to 11.12% (compared to 8.38% to 11.32%, as of April 15, 2014), excluding sustainable growth. Hevert Rebuttal Testimony, p. 70, Tables 9a and 9b; Rebuttal Exhibit RBH-3; Hevert PFT, p. 24, Exhibit RBH-3.

The Company also developed a multi-stage DCF model which is an extension of the constant growth form that enables the analyst to specify growth rates over three distinct stages. Hevert PFT, p. 24. In the first two stages, cash flows are defined as projected dividends. In the third stage, cash flows equal both dividends and the expected price at which the stock will be sold at the end of the period (terminal price). In each of the three stages, the dividend is the product of the projected EPS and the expected dividend payout ratio. Mr. Hevert relied on the projected payout ratios as reported by Value Line and used a long-term growth rate of 5.70% which is based on the real GDP growth rate of 3.27% from 1929 through 2013, and an inflation rate of 2.36%. However, Mr. Hevert subsequently updated the long-term nominal growth rate to 5.74%. Mr. Hevert testified that the slight change was due to an increase in the expected inflation rate. Tr. 9/10/14, pp. 1787–1789. Mr. Hevert calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the cost of equity (discount rate) and the long-term expected growth rate. Hevert PFT, pp. 25 – 27. Using the Gordon model to calculate the terminal value, the multi-stage DCF analysis produced a range of results from 9.51% to 10.58% (compared to 9.46% to 10.75% in the original PFT). Hevert Rebuttal Exhibit RBH-4, pp. 1–20; Exhibit RBH-4, pp. 1-19. Of the three DCF approaches, Mr. Hevert stated that the multi-stage is better in that it provides the ability to take into account the fact that market conditions are changing, that companies may change their payout ratios over time and there may be some compression in the price-to-earnings ratio at the end of the day. Tr. 9/10/14, pp. 1776–1778.

In addition to the DCF models, Mr. Hevert employed the use of a traditional CAPM and an empirical CAPM (ECAPM), which are both risk premium-based models constructed as a forward looking estimate of market equilibrium that measures risk using the beta coefficient. The CAPM analysis estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or systematic risk of the security. Hevert PFT, p. 29. According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to their investment portfolio, investors should be concerned only with systematic or non-diversifiable risk. Hevert PFT, p. 30. Systematic or non-diversifiable risk is measured by the beta coefficient. The basic CAPM is mathematically expressed as:

$$K = R_f + B(R_m - R_f)$$

where: K = required market ROE for a security

B = beta, or systematic risk, for that security

R_f = risk-free rate of return

R_m = required return on market portfolio

$(R_m - R_f)$ = market risk premium

Since electric utilities typically are long-duration investments, the 30-year Treasury yield is most suited for the purpose of calculating the cost of equity. Hevert PFT, pp. 30 and 31. Mr. Hevert used two measures of a 30-year Treasury bond yield and estimated a current rate of 3.35% and a near-term projected rate or consensus forecast of 4.03% as the risk-free rates. Hevert Rebuttal Exhibits RBH-5 and RBH-7. Mr. Hevert claimed that the current rate of 3.35% was the 30-day average as of July 31, 2014. Tr. 9/10/14, p. 1792.

After determining the risk-free rates, Mr. Hevert calculated three versions of the market risk premium. He relied on two forward-looking (ex-ante) estimates and included a third estimate that is a combination of the simple average of the ex-ante method, the Supply Side model, and the long-term historical average market risk premium. Hevert PFT, pp. 31 and 32. His first estimate required the use of Bloomberg as the data source for a DCF-derived market risk premium of 10.12%. Hevert Rebuttal Exhibit RBH-5. The 10.12% was performed by calculating for each of the S&P 500 companies for which Bloomberg provided consensus growth rates which resulted in a 13.47% required market return and then subtracted the 3.35% risk-free rate. The second market risk premium of 10.05% was derived by using the projected earnings growth rates as provided by Value Line which equated to a required return of 13.40% and again subtracting the 3.35% risk-free rate. Id. The third estimated market risk premium of 8.31% is a simple average of incorporating Ibbotson's long-term historical (ex-post) of 6.96% and Supply Side model of 6.12% together with the above ex-ante market risk premiums. Hevert Rebuttal Exhibit RBH-7. All of the expected or required market returns use analysts' EPS growth rate projections.

As for the betas, Mr. Hevert considered the beta coefficients reported by Bloomberg and Value Line for his 14-member proxy group. Hevert PFT, p. 32; Rebuttal Exhibit RBH-11. Updating the data for the 14-member proxy group, the average proxy group beta from Bloomberg was 0.783 and Value Line was 0.74. Hevert Rebuttal Exhibit RBH-6. While the betas are very similar, Mr. Hevert explained that Value Line calculates the beta coefficient over a five-year period and Bloomberg's is based on two years of data. Hevert PFT, p. 33. Based on the updated figures and the variations discussed above, Mr. Hevert produces CAPM results in the range of 9.46% to 11.96%, a decrease from the prior range of 9.74% to 12.16%. Hevert Rebuttal Testimony, p. 72, Table 10.

Mr. Hevert also included the ECAPM analysis in estimating the cost of equity, which is another variation of the CAPM. Hevert PFT, pp. 33 and 34. Mr. Hevert believes the ECAPM addresses the tendency of the traditional CAPM to under-estimate ROEs for low beta stocks such as regulated utilities. The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium, and applies a weight of 75% to that result. His model then applies a 25% weight to the market risk premium. The results of the two calculations are summed, along with the risk-free rate and takes on the following form:

$$K_e = R_f + 0.75B(R_m – R_f) + 0.25(R_m – R_f)$$

As with the CAPM, Mr. Hevert used the market DCF-derived ex-ante market risk premium estimates, the two measures of the 30-year Treasury yield as the risk-free rates and two estimates of the beta coefficient. Updating the inputs as of July 31, 2014, Mr. Hevert's ECAPM results currently range from 10.01% to 12.51%, compared to 10.21% to 12.74% as of the data provided April 15, 2014. Hevert Rebuttal Testimony, p. 72, Table 10; Hevert PFT, p. 34, and Table 9.

Besides the traditional CAPM and ECAPM, Mr. Hevert also evaluated the cost of equity for CL&P utilizing the bond yield plus risk premium method (RPM). Hevert PFT, pp. 34 – 37. The risk premium approach is similar to the CAPM in that the equity risk premium measures the additional risk required by investors for investing in equities rather than less risky assets, such as a company's debt. Typically, the RPM uses a market-based estimate to serve as a proxy for the market's return. Mr. Hevert used an alternative approach by gathering data from 1980 through July 31, 2014, of the actual authorized returns for electric utilities to serve as the proxy for estimating the equity risk premium. Id.; Hevert Rebuttal Testimony, p. 72. He defined the risk premium as the difference between the authorized ROEs and the then-prevailing level of long-term 30-year Treasury yields which resulted in the long-term average equity risk premium of 4.44%. Rebuttal Exhibit RBH-8, p. 18. However, Mr. Hevert stated that simply applying the long-term average equity risk premium of 4.44% would significantly understate the cost of equity and produce results well below any reasonable estimate. Hevert PFT, p. 37; Tr. 9/10/14, pp. 1795 – 1798. Because the data covers a number of economic cycles, Mr. Hevert used a regression analysis approach to measure the equity risk premium relative to a proportional change in the 30-year Treasury yields. To account for that variability, the risk premium is expressed as:

$$RP = a + B(\ln(T_{30}))$$

The results of the regression analysis confirms the inverse relationship between the relatively low level of the current 30-year Treasury yields and the equity risk premium. Including data through July 31, 2014, the 4.44% equity risk premium was adjusted further to 6.79%, 6.26% and 5.41% to reflect the relatively low yields of the current, projected near term and projected long-term, respectively. Rebuttal Exhibit RBH-8, p. 1. Adding the adjusted equity risk premiums to the current and projected 30-

year Treasury yields, resulted in an implied RPM range between 10.14% and 10.86% based on updated data through July 31, 2014.

In summary, Mr. Hevert's updated results determining the cost of equity using the Constant Growth DCF, Quarterly Growth DCF, Multi-stage DCF, CAPM, ECAPM and RPM methodologies to support a recommended range of 10.20% to 10.70%, with the allowed ROE of 10.20%. Mr. Hevert subsequently updated the analyses for the proxy group based on updated data through July 31, 2014. Mr. Hevert's cost of equity calculations were primarily based on a final proxy group of only 14 publicly traded utility companies. The following charts provide a summary of Mr. Hevert's ROE calculations, using updated data through July 31, 2014.

Table 58
Summary of CL&P's ROE Results

DCF Results - Including Sustainable Growth:

Constant Growth DCF	Low	Mean	High
30-Day Average	7.58%	9.10%	10.78%
90-Day Average	7.64%	9.17%	10.85%
180-Day Average	7.75%	9.27%	10.95%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	7.71%	9.28%	11.02%
90-Day Average	7.78%	9.35%	11.09%
180-Day Average	7.89%	9.46%	11.20%
Multi-Stage DCF	**Low**	**Mean**	**High**
30-Day Average	9.51%	9.89%	10.37%
90-Day Average	9.58%	9.84%	10.45%
180-Day Average	9.70%	10.09%	10.58%

DCF Results - Excluding Sustainable Growth:

Constant Growth DCF	Low	Mean	High
30-Day Average	8.26%	9.43%	10.70%
90-Day Average	8.33%	9.50%	10.77%
180-Day Average	8.43%	9.61%	10.87%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.41%	9.63%	10.93%
90-Day Average	8.48%	9.70%	11.00%
180-Day Average	8.59%	9.81%	11.12%
Multi-Stage DCF	**Low**	**Mean**	**High**
30-Day Average	9.68%	9.98%	10.35%
90-Day Average	9.75%	10.06%	10.43%
180-Day Average	9.87%	10.18%	10.56%

CAPM Results:

CAPM	Bloomberg Derived MRP	Value Line Derived MRP	Average Supply Side Ex-Ante RP
Average Bloomberg Beta - 0.783			
Current 30-Year Treasury (3.35%)	11.28%	11.22%	9.86%
Near Term Projected 30-Year Treasury (4.03%)	11.96%	11.90%	10.54%
Average Value Line Beta - 0.74			
Current 30-Year Treasury (3.35%)	10.79%	10.74%	9.46%
Near Term Projected 30-Year Treasury (4.03%)	11.48%	11.43%	10.15%

ECAPM Results:

ECAPM	Bloomberg Derived MRP	Value Line Derived MRP	Average Supply Side Ex-Ante RP
Average Bloomberg Beta - 0.783			
Current 30-Year Treasury (3.35%)	11.82%	11.76%	10.31%
Near Term Projected 30-Year Treasury (4.03%)	12.51%	12.45%	10.99%
Average Value Line Beta - 0.74			
Current 30-Year Treasury (3.35%)	11.46%	11.41%	10.01%
Near Term Projected 30-Year Treasury (4.03%)	12.14%	12.09%	10.70%

Risk Premium Results:

Bond Yield Plus Risk Premium	30-Year Treasury Yield	Risk Premium	Return on Equity
Current 30-Year Treasury (3.35%)	3.35%	6.79%	10.14%
Near Term Projected 30-Year Treasury (4.03%)	4.03%	6.26%	10.30%
Long Term Projected 30-Year Treasury (5.45%)	5.45%	5.41%	10.86%

Hevert Rebuttal Testimony, pp. 69–73.

Although an explicit adjustment for flotation costs was not added to the recommended ROE of 10.20%, Mr. Hevert calculated a 14 basis point adjustment to reasonably represent flotation costs for the Company. In addition, Mr. Hevert also took into consideration the Company's existing and proposed Earnings Sharing Mechanism, its proposed Decoupling Mechanism, financial and business risks and the capital market environment in determining where the Company's ROE falls within his range of results. These considerations are discussed in more detail in II.F.3.f, Flotation Costs.

c. OCC's Position

Dr. Woolridge advocated a 8.90% ROE in this proceeding based on the capital structure proposed by CL&P which includes a common equity ratio of 50.38%. Woolridge PFT, p. 2. Using the proposed Test Year capital structure and senior capital cost rates, the OCC recommended an overall rate of return of 7.14%. Woolridge Exhibit, JRW-1. Dr. Woolridge employed the use of the DCF and CAPM approaches to a 32-member electric proxy group. Dr. Woolridge also applied these methods to CL&P's cost of capital witness' proxy group of companies. Id.

Dr. Woolridge established a proxy group which consists of 32 publicly-held electric utility companies. Woolridge PFT, p. 13. Dr. Woolridge's proxy group includes companies that meet the following criteria: 1) at least 50% of revenues are from regulated electric operations as reported by *AUS Utilities Report*; 2) listed as an electric utility by *Value Line Investment Survey* and listed as an electric utility or combination electric and gas utility in *AUS Utilities Report*; 3) an investment grade corporate credit and bond rating; 4) has paid a cash dividend for the past three years, with no cuts or omissions; 5) not involved in an acquisition of another utility and not the target of an acquisition in the past six months; and 6) analysts' long-term EPS growth rate forecasts available from Yahoo, Reuters and/or Zacks. The resulting proxy group is comprised of: ALLETE, Inc., Alliant Energy Corporation, Ameren Corporation, American Electric Power Co., Avista Corporation, Black Hills Corporation, Cleco Corporation, CMS Energy Corporation, Consolidated Edison, Inc., Dominion Resources, Inc., Duke Energy Corporation, Edison International, Empire District, El Paso Electric, Entergy Corporation, Great Plains Energy Incorporated, Hawaiian Electric Industries, Inc., IDACORP, Inc., MGE Energy, Inc., Nextera Energy, Northeast Utilities, Northwestern Corporation, PPL Corporation, Pinnacle West Capital Corp., PNM Resource, Inc., Portland General Electric Company, OGE Energy Corp., SCANA Corporation, Southern Company, Westar Energy, Inc. and Xcel Energy, Inc. Dr. Woolridge included CL&P's parent company, NU, into his proxy group simply because it met the selection criteria and given the size of the proxy group, including or excluding NU had no material impact on the results. OCC Response to Interrogatory FI-187. While Dr. Woolridge's proxy group provides a more comprehensive sample to estimate an equity cost rate for CL&P, he also included Mr. Hevert's proxy group in his analysis. Woolridge PFT, p. 14.

The average S&P bond ratings for the Woolridge and Hevert proxy groups are both BBB+, whereas, CL&P's bonds are rated A-. Therefore, based on bond ratings, CL&P's investment risk is below that of the two proxy groups. In assessing the riskiness of CL&P's parent company relative to the proxy groups, Dr. Woolridge compared the beta, financial strength, safety, earnings predictability and stock price stability as published by *Value Line*. NU's risk metrics on all five measures are virtually identical to the average for both proxy groups. Therefore, Dr. Woolridge considers that both proxy groups represent a risk-comparable group for CL&P, but the Company's risk is on the low side of these groups as indicated by the bond ratings. Woolridge PFT, pp. 14 and 15.

In developing a fair rate of return for CL&P, Dr. Woolridge primarily relied on the DCF model to estimate the cost of equity and applied it to the both Mr. Hevert's proxy group and his 32-member proxy group. Woolridge PFT, pp. 24 – 29. Given the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities since returns are set through the ratemaking process, Dr. Woolridge finds that the DCF model provides the best measure of equity cost rates for public utilities. Woolridge PFT, p. 24. The economics of the public utility business indicate that the industry is in the steady-state or constant growth stage of a DCF. Woolridge PFT, p. 28. Using the constant growth version of the DCF method, Dr. Woolridge first calculated the dividend yield by taking the current annual dividend and the 30-day, 90-day and 180-day average stock prices as of July 17, 2014. Tr. 9/10/14, p. 1845; OCC Response to Interrogatory FI-182. The mean and median dividend yields ranged from 3.6% to 3.9% for Woolridge's proxy group and ranged from 3.7% to 4.1% for Hevert's proxy group. Given these ranges, Dr. Woolridge used a dividend yield of 3.8% and 3.9% for Woolridge's and Hevert's proxy group, respectively. Woolridge PFT, p. 29. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. Therefore, to reflect the growth over the coming period, Dr. Woolridge adjusted the dividend yields by one-half the expected dividend growth resulting in an adjusted dividend yield of 3.9% for Woolridge's proxy group and 4.0% for Hevert's proxy group. Woolridge PFT, pp. 29 and 30; Exhibit JRW-10, p. 1.

According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Woolridge PFT, p. 32. Dr. Woolridge stated that the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long-term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Woolridge PFT, p. 34. However, in Dr. Woolridge's opinion, investors are well aware of the upward bias in analysts' EPS growth rate forecasts, and therefore, the DCF growth rate needs to be adjusted downward since the stock prices reflect this bias. Woolridge PFT, pp. 35 and 36. Dr. Woolridge testified that the upward bias is not nearly as severe for electric utilities as it is for companies in general. Tr. 9/10/14, pp. 1847 – 1849. Dr. Woolridge used a dividend yield that reflects the 180-day trading period of average stock prices which mitigates the impact because it reaches back to 2013 when utility stocks were underperforming the overall stock market, as opposed to outperforming. Tr. 9/10/14, pp. 1849 and 1850.

For the growth component of the DCF calculation, Dr. Woolridge used a combination of historic and projected growth rates for earnings per share (EPS), dividends per share (DPS), book value per share (BVPS) and prospective earnings retention rates and earned returns on common equity as provided by *Value Line*. Dr. Woolridge also utilized the average EPS growth rates of Wall Street analysts as provided by Yahoo, Reuters and Zacks. Woolridge PFT, p. 31. Dr. Woolridge employs 13 measures of growth, of which 6 measure historic growth, and 7 are *Value Line* or Wall Street analysts' projections of growth, giving primary weight to the projected EPS growth rate forecasts of analysts. OCC Response to Interrogatory FI-188. For Dr. Woolridge's and Hevert's proxy group, the average of *Value Line's* historical median growth rate measures in EPS, DPS and BVPS is 3.60% and 3.0%, respectively. Woolridge PFT, p. 36; Exhibit JRW-10, p. 3, Panels A and B. The median of *Value Line's* projected growth rates for EPS, DPS and BVPS averaged 4.5% for Dr. Woolridge's proxy group and 4.3% for Hevert's proxy group. Id; Exhibit JRW-10, p. 4. The average of *Value Line's* internal growth for the proxy groups as measured by projected retention rate and return on shareholders' equity are 4.0% and 3.6%, for Dr. Woolridge's and Hevert's proxy group, respectively. Id. The mean and median of the 3 Wall Street analysts' projected EPS growth rates for the proxy groups are 5.0% and 4.9% for Dr. Woolridge's proxy group and 5.4% and 4.8% for Hevert's proxy group, respectively. To derive the overall growth rate for the proxy groups, Dr. Woolridge gathered all the data he collected to establish a range of estimates. Giving greater weight to the projected growth rate figures, Dr. Woolridge used the midpoint of the median range for each, resulting in a DCF growth rate of 4.875% for Woolridge's proxy group and 5.0% for Hevert's proxy group. Woolridge PFT, pp. 38 and 39.

Combining all the components of the DCF model, Dr. Woolridge calculated equity costs rates of 8.80% and 9.0%, for Woolridge and Hevert's proxy group, respectively. The details underlying the DCF-derived cost for equity for each proxy group is shown below.

Table 59

	Dividend Yield	1 + 1/2 Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Woolridge Proxy Group	3.80%	1.02438	4.88%	8.80%
Hevert Proxy Group	3.90%	1.02500	5.00%	9.00%

Dr. Woolridge also performed a CAPM analysis using both proxy groups. To determine an equity cost rate using the CAPM, there are three inputs: 1) the risk-free rate of interest, 2) beta (systematic risk measure), and 3) the expected equity or market risk premium. The yield on long-term Treasury bonds is viewed as the risk-free rate of interest in the CAPM and is readily observable in the markets. The yield on the 30-year Treasury bond has been in the 3.0% to 4.0% range over the 2013 to 2014 time period. Woolridge PFT, p. 41; Exhibit JRW-11. According to Dr. Woolridge, these rates are currently in the 3.35% range. Given the recent range of yields and the higher recent interest rates over the past two years, Dr. Woolridge elected to use 4.0% as the risk-free rate in the CAPM analysis. By using the top end of the range, Dr. Woolridge is building into it, a higher return. Tr. 9/10/14, p. 1853.

Dr. Woolridge stated that beta, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historic betas due to their tendency to regress to 1.0 over time. Woolridge PFT, p. 41. A stock with below average price movement, such as that of a regulated utility, is less risky than the market and has a beta of less than 1.0. Woolridge PFT, p. 42. Dr. Woolridge also found there to be several online investment information services that provide estimates of stock betas and these services can report different betas for the same stock due to the time period over which the beta is measured. As provided in the Value Line Investment Survey, the median betas for the companies in Woolridge's and Hevert proxy groups are 0.75% for both. Id.; Exhibit JRW-11.

The most contentious part of the CAPM is to measure the expected equity or market risk premium. The equity risk premium is the expected return on the stock market (such as, the expected return on the S&P 500) minus the risk-free interest rate (yield on the 30-Year Treasury). While the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market. Woolridge PFT, p. 43. To determine an equity risk premium, the OCC reviewed the results of over 40 equity risk premium studies and surveys performed over the past decade. These included the summary equity risk premium results of: 1) the annual study of historic risk premiums as provided by Ibbotson Associates; 2) ex ante equity risk premium studies commissioned by the Social Security Administration (as well as other similar studies labeled "Puzzle Research"); 3) equity risk premium studies of CFOs, Financial Forecasters, and academics; and 4) Building Block approaches to the equity risk premium. The overall median equity risk premium of these studies is 4.28%. Woolridge PFT, pp. 43 – 46; JRW-11, p. 5. To assess the effect of the earlier studies on the equity risk premium, Dr. Woolridge separately composed the results of the studies that were published after January 2, 2010, and determined a median for this subset is 4.90%. Woolridge PFT, p. 47; Exhibit JRW-11, p. 6. According to Dr. Woolridge, much of the data indicated that the market risk premium is in the 4.0% to 6.0% range and the midpoint of 5% is used as the market risk premium for the OCC's CAPM analysis. Dr. Woolridge testified that he gives more credibility to the New York Fed's survey of numerous Wall Street firms that are actively involved in financial decision-making on a daily basis. Tr. 9/10/14, pp. 1854 – 1857. Based upon analysis and the inputs discussed above, Dr. Woolridge's CAPM resulted in a cost of equity of 7.80% for both proxy groups.

Table 60

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Woolridge Proxy Group	4.00%	0.75	5.00%	7.80%
Hevert Proxy Group	4.00%	0.75	5.00%	7.80%

In summary, Dr. Woolridge calculated equity cost rates of 8.80% DCF for Woolridge proxy group, 9.00% DCF for Hevert proxy group, and 7.80% CAPM for both proxy groups. Given these results, the OCC concludes that the appropriate equity cost rate for the proxy groups is in the 7.80% to 9.00% range. However, since Dr. Woolridge primarily relies on the DCF model, the OCC used the midpoint of the upper end of the range, concluding that 8.90% is the recommended equity cost rate for CL&P. Woolridge PFT, p. 49. Dr. Woolridge discussed several reasons why an 8.90% ROE is appropriate and fair for CL&P in this case: 1) CL&P is slightly less risky than the proxy groups as measured by its S&P bond rating of A-; 2) the electric utility industry is one of the lowest risk industries in the U.S. as measured by beta; 3) capital costs for utilities, as indicated by long-term bond yields and interest rates, are still at historically low levels; 4) while the markets have recovered significantly over the past five years, the growth in the economy is tepid and unemployment is still at 6.1%; 5) utilities have been the best performing sector of the market this past year; and 6) CL&P is a distribution-only electric utility that does not have the risks associated with the generation component of integrated utilities. While Dr. Woolridge did not consider the impact of the Company's proposed decoupling mechanism nor the earnings sharing mechanism on the OCC recommended ROE, he concurred that the mechanisms are reflected in the lower risk of Company. Tr. 9/10/14, pp. 1869 – 1871. Furthermore, Dr. Woolridge provided the authorized ROEs in 18 rate cases in 2013 and 2014 involving distribution-only electric utilities. There are no authorized ROEs of 10% or higher, and the average for the distribution-only electrics is 9.48%. Woolridge PFT, pp. 51 and 52.

Dr. Woolridge critiqued the most significant areas of disagreement in measuring CL&P's cost of capital which are: 1) the DCF equity cost rate estimates; 2) the market or equity risk premium in the CAPM and RP approaches; and 3) whether an equity cost rate adjustment is needed to account for flotation costs. In the DCF approach, the OCC finds there to be three major areas of contention with CL&P's DCF estimates, and in particular, Mr. Hevert's (a) decision to ignore 1/3 of his low-end DCF results, (b) excessive reliance on the long-term EPS growth rates of Wall Street analysts and *Value Line* in developing a DCF growth rate, and (c) employment of an unrealistic projected GDP growth rate in his multi-stage DCF model. Woolridge PFT, p. 53. With respect to the asymmetric elimination of low-end DCF results, Dr. Woolridge stated that Mr. Hevert biases his DCF study and reports a higher equity cost rate than the data indicate. Dr. Woolridge continues that it appears that Mr. Hevert simply ignored the mean low DCF results for his constant and quarterly-growth DCF model application. In comparison, Dr. Woolridge stated that he used the median as a measure of central tendency so as to not give outlier results too much weight while not ignoring the impact of low and/or high results in determining an estimate for DCF. Woolridge PFT, p. 55.

Another area of concern for Dr. Woolridge with Mr. Hevert's DCF is the excessive reliance on the projected EPS growth rate forecasts of investment analysts as compiled by Zacks, First Call and *Value Line* in estimating an equity cost rate. Mr. Hevert's DCF growth rate in all three models employ the overly optimistic and upwardly-biased EPS growth rate estimates of Wall Street analysts. The OCC considered it to be a well-known fact that analysts' EPS forecasts are consistently too high. Woolridge PFT, p. 56 and Appendix B. In comparison, Dr. Woolridge reviews 13 different measures of growth to develop a DCF growth rate, including prospective dividend growth, internal growth, as well as projected earnings growth. Id.

Dr. Woolridge also highlights two critical errors in Mr. Hevert's multi-stage DCF approach which grossly inflates the projection of GDP as a growth rate. Woolridge PFT, p. 59. Dr. Woolridge claims that Mr. Hevert has not provided any theoretical or empirical support that long-term GDP growth is a reasonable proxy for the expected growth rate of the companies in his proxy group. Dr. Woolridge illustrated the historic measures of growth for earnings and dividends for both his and Hevert's proxy group which suggest growth that is 200 basis points below Mr. Hevert's 5.70% GDP growth rate. More importantly, Dr. Woolridge demonstrates that the projected GDP growth rate of 5.70% is not reflective of economic growth in the U.S., and is well in excess of projections of GDP growth. As such, Dr. Woolridge provided evidence that shows nominal GDP as well as its components, real GDP and inflation, have declined significantly in recent decades. Id; Exhibit JRW-14. With respect to GDP forecasts, there are several forecasts available from economists and government agencies of annual GDP growth that show a long-term growth range of 4.5% to 4.8%. Woolridge PFT, p. 61.

The OCC deems there to be two primary errors in Mr. Hevert's CAPM analysis which is the use of the ECAPM and the market premiums. Dr. Woolridge considers the ECAPM as nothing more than an ad hoc version of the CAPM and there is no empirical validation for the use of the weighting factors to boost the equity risk premium measure. Woolridge PFT, pp. 63 and 64. The major area of contention with respect to the CAPM and RP approaches is the measurement and magnitude of the market or equity risk premium. Dr. Woolridge demonstrates how Mr. Hevert's CAPM includes an expected return on the stock market that is not reflective of current market fundamentals, expected earnings, and GDP growth. Mr. Hevert's use of expected EPS growth rates from Wall Street analysts of 11.8% and 10.31% to produce estimated market returns of 13.91% from Bloomberg and 12.31% from Value Line, respectively, are not consistent with historic or projected economic and earnings growth in the U.S. Woolridge PFT, pp. 65 and 66.

The national growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960 has averaged 6.50%, which demonstrates that Mr. Hevert's long-term growth rate projections are vastly overstated. OCC Brief, p. 25. Also, as discussed above, projected long-term GDP growth rate forecasts are in the 4.5% to 4.8% range. Woolridge PFT, p. 67. Moreover, the risk premium in Mr. Hevert's RP approach, which is based on the difference between authorized ROEs for electric utility companies and Treasury yields, is overstated because the approach uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields. Woolridge PFT, p. 72. In comparison, Dr. Woolridge uses a market risk premium which uses alternative approaches to estimating a market premium, and employs the results of over 30 studies and surveys of the market risk premium. Dr. Woolridge stated that his market risk premium is consistent with the market risk premiums: 1) discovered in recent academic studies by leading finance scholars; 2) employed by leading investment banks and management consulting firms; and 3) that result from surveys of companies, analysts, financial forecasters and corporate CFOs.

Mr. Hevert supported his DCF, CAPM and RP results with claims that the current market environment, flotation costs, and other factors suggest a higher equity cost rate is justified. Dr. Woolridge demonstrates that these factors should not be considered in setting the appropriate equity cost rate for CL&P.

d. Intervenors' Positions

i. Wal-Mart Stores

Pre-filed testimony of Steve W. Chriss, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. (collectively, Wal-Mart) was submitted with a recommendation concerning the ROE. Mr. Chriss demonstrates that the Company's proposed ROE of 10.2% is higher than ROEs approved by the Authority since CL&P's last rate proceeding and higher than those approved by other utility regulatory commissions. Chriss PFT, p. 17. As Mr. Chriss points out, there is a declining trend in authorized ROEs, particularly for distribution-only utilities. According to data from Regulatory Research Associates,[19] the average of 101 reported electric utility rate case ROEs authorized by commissions in 2012, 2013 and so far in 2014, is 9.91%, with a reported range of 8.72% to 10.95%. Chriss PFT, p, 18. The reported ROEs authorized by commissions were also recognized in Mr. Hevert's rebuttal testimony. Hevert Rebuttal Exhibit, RBH-20. However, the average reported ROE for distribution-only utilities was 9.57%, which is 63 basis points lower than CL&P's proposed ROE. Chriss PFT, p. 18. Mr. Chriss also revealed that in 16 recent utility rate cases in which Mr. Hevert provided expert testimony, the approved ROE decided in each case was lower than Mr. Hevert's recommended ROE in all cases. Chriss Late Filed Exhibit No. 35. In fact, each of the

[19] Regulatory Research Associates is part of SNL Financial, a financial news and reporting company.

16 recent cases in which Mr. Hevert provided expert testimony, all of the final approved ROEs were below Mr. Hevert's recommended ROE ranges. Id.

Mr. Chriss recommended that the Authority continue its practice of using recent Decisions to establish benchmark parameters and to indicate in which direction the allowed ROE should trend. Chriss PFT, p. 19. In addition, Mr. Chriss suggests that if the Authority approves a decoupling mechanism and earnings sharing mechanism for CL&P, it should consider the extent to which the implementation of these mechanisms reduces the business risk and be reflected in the Company's approved ROE. Chriss PFT, p. 4.

ii. AG's Position

The AG stated that the Authority should reject CL&P's proposed ROE of 10.2% since it is not consistent with recent PURA Decisions or analysis and is based on flawed and unreliable cost of capital analyses. AG Brief, p. 3. The AG generally supported the OCC's cost of capital testimony and its recommended ROE of 8.9%. However, the AG argued that the Authority should impose additional reductions to CL&P's authorized ROE to reflect the reduced business and operations risk from the revenue and sales decoupling mechanism. Id.

The AG contended that the Company's ROE is far out of line with recent Authority Decisions and would be the highest authorized return for any major regulated public service company in Connecticut. In the last 18 months, the Authority has not authorized a ROE over 9.2% and cites to the recently awarded returns of Connecticut Natural Gas Corporation, The United Illuminating Company and Aquarion Water Company of Connecticut. AG Brief, pp. 4 and 5. The AG also argued that CL&P's testimony in support of its proposed ROE of 10.2% contains errors that have distorted the Company's DCF, RP and CAPM analyses and unreasonably inflated its proposed ROE as demonstrated by the testimony and exhibits of the OCC's witness. As a result, the Company's recommended ROE is substantially higher than other similarly situated utility companies and substantially higher than the levels that the PURA recently approved for Connecticut's other public service companies. Id.

e. Authority Analysis – Cost of Equity

The Authority assessed the testimonies and recommendations of Mr. Hevert and Dr. Woolridge and is confident that the best solution to CL&P's cost of equity capital requirements still exists within the framework of the DCF model while considering the results of the CAPM. To test the results of the Company and the OCC witnesses, the Authority conducted its own cost of equity analysis of regulated utilities in an effort to take into account the differing approaches to estimating the cost of equity. The Authority's cost of equity analysis is based on the consensus positions and evidence gathered in Docket No. 09-10-06, Investigative Inquiry into the Desirability, Need and Feasibility of Establishing a Uniform Methodology for Determining Return on Equity (2009 Generic ROE Proceeding) in order to maintain consistency among rate proceedings. The Authority also takes notice that the testimony, arguments, calculations and methodologies by the OCC's consultant, have been uniform in the last several rate proceedings and have proved to be unfailing.

i. Analysis of the DCF Proposals

Since CL&P's stock is not publicly traded, a proxy group of companies comparable to CL&P must be developed in order to estimate the cost of equity. With regard to the choice of a proxy group, the Authority considered the Company and the OCC witnesses' proxy groups. The OCC chose to use the same 14-member proxy group derived by CL&P, as well as Dr. Woolridge's selection of a 32-member proxy group and performed analyses for both groups. Both the Company and the OCC used similar criteria in the selection of their proxy groups, such as those followed by Value Line, paid consistent quarterly dividends, covered by at least two utility industry equity analysts, an investment grade corporate credit and bond rating, and not involved in a merger, acquisition or other significant transaction. The Authority finds these to be reasonable factors to consider in the selection of the proxy companies.

The Authority takes issue with the percentage of regulated business criteria and it is the major difference between the Company and the OCC in that selection criteria. For example, the OCC recommended that proxy group companies have at least 50% of revenues from regulated electric business as reported by AUS Utility Reports. Alternatively, the Company cited that the basis for selecting its proxy electric companies was that it should represent at least 60% of total regulated operating income and 90% or greater of income from regulated electric operating income as conveyed in each companies' respective SEC 10-k filings and reported by SNL Financial. The difference of regulated operating revenues versus income and the source used to derive the data is not much of a concern as is the disproportion in the percentage of regulated business considered. The Company's selection criteria of having at least 90% of its regulated business from electric utility operations resulted in the elimination of 25 companies from Value Line's universe of 47 electric utility companies. This factor alone caused the greatest disparity between the Company and the OCC proxy group of companies. The Authority finds the Company's elimination of companies with less than 90% regulated income to be too restricting, while the OCC's criteria of at least 50% regulated revenues, too broad.

With respect to the proxy group selection criteria, the Authority reviewed prior rate proceeding decisions and closely followed the discussions by the parties in the 2009 Generic ROE Proceeding. According to the consensus, the Authority finds that the percentage of regulated business criteria to be 70% of regulated electric revenues as followed by *AUS Utility Reports*. The Authority finds the 70% valuation for an electric utility as appropriate and allows the PURA to create a pure play electric proxy group. Although it is not as restricting as the Company's 90% criteria, the Authority finds the 70% threshold still results in a large, robust proxy group. Including this modification to this selection criteria, the Authority's approved electric peer group (Authority Peer Group) represents the following selection criteria: 1) followed by Value Line; 2) has consistently paid dividends; 3) covered by at least two utility industry equity analysts; 4) has investment grade corporate credit and bond ratings; 5) not involved in a merger or takeover activity; and 6) 70% or more of revenues should be from regulated electric operations. Thus, the proxy group employed by the Authority to determine the cost of equity for CL&P lead to an Authority Peer Group of 25 comparable companies which includes: (ALLETE, Alliant Energy Corporation, Ameren Corporation, American Electric

Power, Consolidated Edison, Duke Energy, Edison International, Empire District, El Paso Electric, Entergy Corporation, Great Plains Energy, Hawaiian Electric, IDACORP, NextEra Energy, Northeast Utilities, NorthWestern Corporation, PG&E Corporation, Pinnacle West Capital Corporation, PNM Resources, Portland General Electric, OGE Energy, Southern Company, TECO Energy, Westar Energy, Xcel Energy). The table below provides a comparison of the proxy companies proposed by the Company, the OCC and also indicated those that passed the Authority's criteria.

Table 61

Hevert: Company Proxy Group	Woolridge: OCC Proxy Group	Authority Peer Group
	ALLETE, Inc.	ALLETE, Inc.
	Alliant Energy Corporation	Alliant Energy Corporation
	Ameren Corporation	Ameren Corporation
American Electric Power Co.	American Electric Power Co.	American Electric Power Co.
	Avista Corporation	
	Black Hills Corporation	
Cleco Corporation	Cleco Corporation	
	CMS Energy Corporation	
	Consolidated Edison, Inc.	Consolidated Edison, Inc.
	Dominion Resources, Inc.	
Duke Energy Corporation	Duke Energy Corporation	Duke Energy Corporation
	Edison International	Edison International
Empire District	Empire District	Empire District
	El Paso Electric	El Paso Electric
	Entergy Corporation	Entergy Corporation
Great Plains Energy Inc.	Great Plains Energy Inc.	Great Plains Energy Inc.
Hawaiian Electric Industries, Inc.	Hawaiian Electric Industries, Inc.	Hawaiian Electric Industries, Inc.
IDACORP, Inc.	IDACORP, Inc.	IDACORP, Inc.
	MGE Energy, Inc.	
Nextera Energy	Nextera Energy	Nextera Energy
	Northeast Utilities	Northeast Utilities
	NorthWestern Corporation	NorthWestern Corporation
	PPL 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.
	OGE Energy Corp.	OGE Energy
Otter Tail Corporation		
	SCANA Corporation	
Southern Company	Southern Company	Southern Company
Westar Energy, Inc.	Westar Energy, Inc.	Westar Energy, Inc.
	Xcel Energy Inc.	Xcel Energy Inc.

In reviewing the DCF approaches, the Authority finds it necessary to address several differences between the Company and the OCC witnesses' applications of the model. Both the CL&P and the OCC witnesses incorporated the standard version of the DCF model to their proxy groups where the current dividend payment and stock price are directly observable. Although Mr. Hevert provided additional versions for estimating the DCF, such as the Quarterly and Multi-stage forms, the Authority finds the constant growth DCF model to be applicable due to the regulated stability and nature of public utilities, as well as the fact that returns on investment are effectively set through the ratemaking process. The basic fundamentals of a regulated utility, such as CL&P, indicated that the industry is in a mature or steady-state stage of the three-stage DCF.

The DCF valuation approach for companies in this industry is the constant growth DCF. The constant growth DCF model is widely-accepted in the utility industry and is the most common method to calculate the ROE in regulatory proceedings. Consistent with past practice and industry standards, the Authority's preferred method is the constant growth form of the DCF that assumes dividends grow at a constant rate which simplifies to $K = D_1/P_0 + g$. Although the DCF seems straightforward, its components can vary widely depending on the type of growth measured and the time period selected. The Authority also considers the extent to which economic anomalies may affect the DCF analyses and prudently selects the individual components based on the current conditions within the constraints of the model and closely following the consensus of the 2009 Generic ROE Proceeding. The Authority is cognizant of the current market conditions and their relevant impact on growth rate recommendations, and reserves the right to use its judgment to form a reasonable estimate for the expected growth rate portion of the DCF model. As with each rate proceeding, a major point of contention is the computation of the growth component in the DCF, which is discussed further below.

After selecting the Authority Peer Group, the first step in the DCF is to calculate the average dividend yield. Both the Company and the OCC compute the dividend yield in a similar manner by using the proxy companies' current annualized dividends and average closing stock prices over the 30, 90 and 180 trading day periods and then adjusts the dividend yields by applying one-half of the long-term growth rate to the current dividend yield. Mr. Hevert's updated computation for the period ending July 31, 2014, resulted in adjusted dividend yields of 3.81%, 3.88% and 3.99%. Using both Mr. Hevert's proxy group and the OCC's 32-member proxy group, Dr. Woolridge employed the same approach for an adjusted dividend yield, but used the average stock prices as of July 17, 2014, to arrive at an adjusted dividend yield of 4.0% for Mr. Hevert's proxy group and 3.9% for OCC's proxy group.

Although the Company and the OCC employed comparable approaches to forecast the dividend yield in this proceeding, there is usually great deliberation over how much growth is to be applied (full year or half year) to forecast the dividend portion. To be consistent with prior proceedings, the Authority will incorporate *Value Line's* estimate of dividends to be paid over the next 12 months from *Value Line: Summary & Index*, column (f) as the D_1 input to the DCF model. This is based in part on evidence in the 2009 Generic ROE Proceeding and the fact that it is simply easier to utilize a number reported in *Value Line* than debate how much growth to be applied to inflate the current dividend. This debate can be lengthy in proceedings and the impact is *de minimis*. In fact, Mr. Hevert did not disagree with the Authority's use of *Value Line* as a sole source for projected dividends. Even though Mr. Hevert elected to use Bloomberg Professional Service as a source because it reflects the views of multiple analysts, he noted that the difference in results between the two sources is not significant. The Authority's analysis used *Value Line: Summary & Index* dated August 29, 2014, to obtain estimates of dividends to be paid over the next 12 months (D_1).

Regarding the time period that the data is collected, the Authority finds a 30-day average stock price long enough to capture changes in stock price movements and relatively simple to obtain from public sources online. Both the Company and the OCC used the average closing stock prices over three various time periods (30, 90 and 180 trading days) as its low, mean and high range for the dividend yield. The Authority incorporates a timeframe of 30 business days, or approximately 6 weeks, as reasonable for estimating the stock price portion for the dividend yield component of the DCF model. The Authority's time period covered six weeks ended August 29, 2014. Based on the Authority's Peer Group, resultant forecasted dividend yields used in the Authority's DCF model range from a minimum of 2.54% to a maximum of 5.17%. The mean (average) is 3.87%, while the median is virtually identical at 3.95%.

Next step is the calculation of long-term growth rates which is the most complex and debated issue of all the DCF components. There was agreement from the Company and the OCC that professional stock analysts' five-year forecasts for EPS growth and *Value Line's* projections for EPS should be included in the estimation of the overall growth component to apply in the DCF model. Mr. Hevert used a consensus of long-term earnings growth estimates from Zacks, First Call and *Value Line* which reports the lowest, average and highest projected growth rates. Dr. Woolridge elected to use *Value Line's* projected growth rate estimates and the EPS growth rate forecasts as provided by Yahoo, Zacks and Reuters. The Authority finds little debate with regards to the incorporation of which professional analysts' EPS estimates to include and integrates EPS growth projections from *Value Line*, Yahoo Finance/I/B/E/S and Zacks.[20] The Authority chose not to include Thompson Reuters as a source of EPS forecasts since it would be redundant to Yahoo Finance which lists Thompson Reuters as the source of its summary EPS forecasts. For the Authority Peer Group, examination of the EPS growth rate data reveals a range of 1.0% minimum to a maximum of 11.0%, while the mean-average of the three estimates taken together was 4.94% and their median was 4.79%.

One area of contention between the Company and the OCC is over the inclusion of *Value Line's* projections for DPS and BVPS. Mr. Hevert chose only to focus on earnings growth in his analysis because earnings are the fundamental measure of growth, whereas, earnings growth enables both dividend and book value growth. Conversely, Dr. Woolridge included *Value Line's* projected growth rate estimates for DPS and BVPS as well as, the historic growth rates for EPS, DPS and BVPS. There is general agreement that the DCF concept presumes that earnings, book value, market price and dividends all grow at the same rate. The Authority finds that under the DCF theory and financial literature in general, all earnings will eventually accrue to investors through dividends and eventual sale of the stock. Even so, the cash stream an investor receives is a dividend and not the company's earnings. In reality, the investor only shares in those company earnings to the degree and timing the company wants the investor to participate in the company's performance (i.e., the dividend). A similar

[20] Value Line projected EPS, DPS and BVPS growth rates were obtained from the August 22, 2014 East edition; the August 1, 2014 West edition, and the June 20, 2014 Central edition. The 5-year EPS growth rates for Yahoo Finance (www.finance.yahoo.com) and Zacks (www.zacks.com) were obtained from their Internet domains on September 5, 2014 and September 8, 2014, respectively.

argument can be made for the inclusion of the BVPS growth rate into the DCF model since BVPS represents the underlying investment which generates earnings and therefore, dividends. Lastly, from a more practical view point, the Authority finds that it is unlikely that an investor would examine the *Value Line* sheet for a company and look only for the EPS projections while those forecasts for DPS and BVPS are also there. Based upon its review, the Authority finds DPS and BVPS to be relevant growth rates and incorporates *Value Line's* projections for DPS and BVPS in its analysis. For the Authority Peer Group, examination of the forecasted DPS and BVPS growth rate data reveals a range of 1.0% minimum to a maximum of 12.0%, while the mean-average of both estimates taken together was 4.44% and their median was 4.0%. Evidence shows the DPS and BVPS projections are slightly lower than those projections for EPS growth rates.

Another disparity between the Company and the OCC was the inclusion of *Value Line's* historic growth rates for EPS, DPS and BVPS in the estimation of the growth rate to be used in the DCF model. The OCC suggests that historic rates should be considered to provide a baseline of growth since investors have access to historic information, which provides the basis for investors' investment decisions. However, it appears Dr. Woolridge did not include the historic growth rate figures (3.6% and 3.0%) when establishing the appropriate growth rate range of 4.75% to 5.0%. The OCC explained that the projected rates are given more weight compared with the historic rates. While investors may not prefer or rely on historical growth estimates, the Authority does not believe investors completely ignore past history. However, the Authority finds that the *Value Line* historic growth rates for EPS, DPS and BVPS should not be a separate input included in a composite growth rate for the DCF model in this proceeding. Although historic growth estimates are excluded from the expected growth component of the DCF model, this does not suggest these historic growth figures have no place in the DCF analysis as they indicate the reasonableness of analyst forecasts. Therefore, the Authority considered the *Value Line's* 5-year and 10-year historical growth rate estimates for EPS, DPS and BVPS only as a base line measurement means for evaluation of the forecasts.

In addition to the growth rates discussed above, the Company and the OCC have included a sustainable or retention growth rate (retention rate = br + sv) as a measure of expected growth in the DCF analyses. According to financial theory, the sustainable growth formula (g = ROE x retention rate) is the best measure to estimate long-term growth rate expectations and the growth rate component of the DCF. As in past practices, the Authority focuses on the 'br' portion (internal growth) that is known as the earnings retention rate times the projected ROE. The primary debate with the sustainable growth rate is regarding the 'sv' portion (external growth) of the retention growth formula. There is agreement that *Value Line's* projections of BVPS take into account external growth. Likewise, the 'sv' portion is only applicable when a company is in the process of issuing stock to achieve external growth.

The Authority realizes that it is difficult to determine 'sv' as one needs to know when a utility will undertake a stock offering and even more difficult to determine the market-to-book ratio of that stock offering at the time of its issuance. Under this circumstance, the 'sv' portion should be widely disseminated to the investment public and should be known and measurable. This is unlikely to happen as companies do not normally publicly report their plans to issue equity well in advance of the issue. It is clear that the greater portion of the sustainable growth rate does come from the 'br' portion. Examining the Company's assumption for estimating the 'sv', Mr. Hevert used the projected market-to-book ratio and the growth rate in common shares outstanding for the 's' portion while the 'v' portion was computed as 1 minus the projected market-to-book. In this case, the Company used *Value Line* projections for the increase in number of shares outstanding for each member of the proxy group. In other words, an assumption is being made that all the proxy group companies will be issuing shares and at an increase in value or at a price greater than book value.

The Authority finds this to be an unlikely assumption. Consequently, the Authority includes the sustainable growth formula, but places no weight on the 'sv' portion of the equation. The Authority's 'br' computation is obtained from the final projection's column (years 17-19) from *Value Line* company sheets. For the Authority Peer Group, examining the computed sustainable growth rate data shows that it ranges from a minimum of 2.47% to a maximum of 5.90%, with a mean-average of 3.90% and median of 3.72%.

To fully develop an understanding of what the composite or overall long-term growth will be for a company, various growth rates including dividend, earnings and book value growth must be taken into consideration. It is apparent that growth rates vary widely depending on the type of growth measured and the time period selected. The Authority was vigilant in analyzing different subsets of time periods within each type of growth rate because averaging different years or months of data can produce widely different results due to short-term fluctuation and oscillations in security prices. Also, the Authority finds sustainable growth is a significant and primary driver of long-run earnings growth. In its analyses, the Authority incorporated measures of growth for EPS, DPS, BVPS, as well as, sustainable growth rates. Prior to the close of the record in this proceeding, the Authority applied the latest editions and most recent measures of data found in the record or publicly available online in its analyses.[21] Use of the most recent issue of the Mergent Bond Record, Value Line editions, EPS estimates and updated stock prices revealed a decrease in interest rates, stock prices and growth rates since the Company and the OCC submitted their analyses.

In applying the DCF model, the Authority reviewed the annual constant growth form and incorporated a screening mechanism, based upon the rationale that the cost of equity should be greater than the cost of debt due to equity's greater risk. The Authority used the data in the record employing different measures of growth, including *Value Line's* 5-year projected growth rates for EPS, DPS and BVPS, as well as growth rates computed using the sustainable earnings/retention growth formula. The Wall Street analysts' forecasts of EPS obtained from Yahoo Finance and Zacks were also

[21] Value Line projected EPS, DPS and BVPS growth rates were obtained from the August 22, 2014 East edition; the August 1, 2014 West edition; and the June 20, 2014 Central edition. The 5-year EPS growth rates for Yahoo Finance (www.finance.yahoo.com) and Zacks (www.zacks.com) were obtained from their Internet domains on September 5, 2014 and September 8, 2014, respectively. The stock prices were derived from the historical prices from Yahoo Finance for a 30-day trading period ending August 29, 2014. The cost of debt recent issue was the August 2014 Mergent Bond Record.

incorporated into the DCF analysis. Overall, the Authority computed several scenarios using different estimates of growth. No one growth estimate was favored in place of another.

In the case of the electric industry, the Authority implements more stringent screening criteria as there is a large universe of publicly traded electric utilities. In addition to the initial proxy group screening criteria discussed above, the Authority set an acceptance criterion relative to the individual DCF results. With the changing market conditions, the Authority finds the screening mechanism for implausibly high and low DCF results to be beneficial. Regarding the low side threshold, the Authority finds as reasonable, the concept that equity is more risky than debt. Traditionally, the Authority's method has been to add 100 basis points to the average Mergent Public Utility Bond yield as its low end to screen individual DCF estimates. The cost of debt benchmark consists of the most current effective cost of long-term debt rate for each Authority Peer Group company using the latest Mergent Bond Guide as the source for the corporate bond yield averages. With the continuous decline in interest rates combined with the decrease in stock prices and growth rates, the Authority observed the individual DCF estimates also have fallen.

The latest Mergent Bond Record, August 2014 edition indicates that over the time period this rate proceeding commenced, the average Aa Public Utility Bond yield ranged from 4.23% to 4.07%. Applying the concept that equity is more risky than debt, the Authority finds it reasonable to increase the minimum basis point threshold above the cost of debt from 100 basis points to 375 basis points. Raising the minimum threshold to 375 basis points had the effect of eliminating 10 companies that had DCF estimates ranging from 6.49% to 8.22%. Those companies excluded were: American Electric, Consolidated Edison, Duke Energy, Edison International, El Paso Electric, Empire District, Entergy, IDACORP, PG&E Corporation and Pinnacle West.

Regarding the high side threshold, the Authority did not find it necessary to change the maximum benchmark set at 750 basis points and there were no companies eliminated. In this case, a definitive high end screen was not necessary given the DCF indicated results are low and below 10%. After establishing the minimum and maximum thresholds for the Authority Peer Group, the DCF estimate shows that it ranges from 8.02% to 10.69% with a mean-average of 9.03% and a median of 8.79%. The Authority finds the average of 9.03**%** to be a reasonable estimate of the indicated DCF cost of capital methodology. The Authority also finds this result is very conservative given the elevated threshold for screening the lower DCF estimates. Furthermore, the Authority highlights the fact that the Company's own constant growth DCF analysis using the 30-day average stock price, including its version of sustainable growth, produced DCF results of 7.58%, 9.10% and 10.78% for the low, mean-average and high, respectively.

ii. Analysis of the Capital Asset Pricing Models

The Authority evaluated the CAPM approaches employed by the Company and the OCC witnesses. There are several debates surrounding the application of the CAPM methodology, such as the actual use of other non-traditional forms of the CAPM and the equity risk premium estimates. The major controversy contiguous to the CAPM is always the calculation of the equity or market risk premiums. The Authority applied the traditional CAPM to its proxy group using the standard formula of $K = R_f + B (R_m - R_f)$. The Authority applied an equity risk premium based on data of equity risk premiums in the record.

Reviewing the evidence regarding the selection of the risk-free rate of interest (R_f), does not show much controversy. The Company used two measures of a 30-year Treasury bond yield and estimated a current rate of 3.35% and a near-term consensus forecast of 4.03%. The OCC also recommended the recent 30-year Treasury bond yield of 4.0% to be conservative based on its observation that the 30-year Treasury bond yields have ranged between 3.0% to 4.0% over the 2013 to 2014 time period. The Authority reviewed recent trends in 30-year Treasury bond yields and finds that these have bounced up and down since 2013; however, since the beginning of 2014 interest rates have slowly decreased again. In fact, on the last day of hearings, before the record closed, the 30-year Treasury bond yield was 3.22%.[22] To be conservative, the Authority finds it reasonable to use the average of the Company (3.69%= [3.35%+4.03%]/2) and the OCC proposals of 3.845% (i.e., [3.69%+4%]/2) as an acceptable proxy for the return on long-term risk-free rate of interest, and incorporates this into its CAPM analysis.

The measure of beta represents the volatility of a proxy group of companies to the aggregate market. The OCC recommended use of *Value Line* adjusted betas, while Mr. Hevert considered the beta coefficients reported by both *Value Line* and Bloomberg. The Authority is aware that there are several online sources that provide estimates of stock betas and these services can report different betas for the same stock due to the time period over which the beta is measured. The Authority has relied on *Value Line* adjusted betas in the past, and therefore, incorporates *Value Line* betas into its analysis. The average beta of the Authority Peer Group is 0.75.

The primary concern with the CAPM is the estimation of the expected equity or market risk premium ($R_m - R_f$). The Company used three market risk premium measures of 10.21% (an ex-ante DCF-derived market risk premium from Bloomberg), 10.05% (an ex-ante market risk premium utilizing data from *Value Line*) and 8.31% (a simple average of the ex-ante Ibbotson model, Supply Side model, and ex-post or long-term historical average). With respect to Mr. Hevert's ex-ante measures using data provided by Bloomberg and *Value Line*, the Authority reviewed the Company's approach of using a DCF analysis on companies in the S&P 500 and back into a market risk premium and finds it to be an interesting approach to take. On the surface, the approach seemed reasonable but the Authority took issue with the execution of the method, especially with the expected EPS growth rates from Wall Street analysts used as inputs.

The Authority concurs with the OCC that these growth rates of 11.8% from Bloomberg and 10.31% from Value Line are inflated and not consistent with either historic or projected economic and earnings growth in the U.S. Of course, estimating the inputs to the DCF approach to generate an estimated return on the market requires

[22] The Company agreed to take administrative notice of recent and historical US Treasury Rates from www.treasury.gov in its Response to Interrogatory FI-67.

using analyst estimates of growth. Although it is difficult to evaluate the level of optimism in Wall Street analysts projected growth rates, it is a factor that needs to be considered in the evaluation of cost of capital especially when expected growth rates are involved. Regarding the Company's third approach to estimating a market risk premium, the Authority finds this to be a simple blending of the ex-ante and ex-post approaches that temper the impact of any one result of a particular method. The Authority included all three of the Company's market risk premium measures in its overall computation of a reasonable estimate for the equity risk premium, but gave these measures only one-third weight.

Regarding the OCC's equity risk premium, the Authority finds Dr. Woolridge's approach to be the most comprehensive in that it incorporates over 40 equity risk premium studies and surveys performed over the past decade. The OCC's recommended average market risk premium of 5.0% also incorporates the Ibbotson historical approach, as well as, both the arithmetic mean and the geometric mean approach. The OCC's approach is the most inclusive and has been included as an approach in numerous previous Decisions. Therefore, the OCC's proposed 5% is included in the Authority's methodology and is also given one-third weight in estimating the overall equity risk premium.

The Authority's review of equity risk premium determines that an investor should not expect a return much different than that produced by companies in the economy. In reviewing the methodologies presented, the Authority is drawn to the Ibbotson Supply Side Model. The Ibbotson Supply Side Model suggests that equity returns consist of inflation, the growth in real EPS, and income returns. The Authority notes that both the Company and the OCC presented the supply side within their estimate of the equity risk premium. One difference between the supply side model and the historical model calculations of Ibbotson is that the supply side excludes the growth in the price earnings ratio. Both calculations use the arithmetic mean and the difference is modest. For example, over the time period 1926-2013, the historical approach yields an equity risk premium of 6.20% while the supply side approach yields 6.12%. The Authority finds that the Ibbotson supply side approach is responsive to problems and biases contained in the historical data and is the best approach. Thus, the Authority incorporates the Supply Side equity risk premium of 6.12% and will apply to it a one-third weight in developing its equity risk premium.

In addition to the traditional CAPM, the Company proposed another variation known as the ECAPM which is basically a size or leverage adjustment of beta that increases the expected returns for low beta stocks and decreases returns for high beta stocks. As discussed previously, both the OCC and the Company used the Value Line betas which have been adjusted to address the empirical issues with the CAPM. The Authority has reviewed Mr. Hevert's ECAPM and finds that the only difference between the CAPM and ECAPM is the use of the weights or Alpha factor which is an arbitrary figure and has not been validated in referred journals. The Authority finds that the Alpha factor incorporates another level of conjecture that is unnecessary given that the simple CAPM formula is widely accepted in the cost of equity literature. Furthermore, the Authority has previously rejected the use of the ECAPM in numerous rate proceedings.[23] As a result, the Authority rejects the notion of adding more layers of speculation or another variation to the CAPM, therefore, the Authority discards the ECAPM estimates from its analyses.

As with past practice, the Authority implemented a traditional CAPM cost of equity using the standard formula. First, the Authority incorporates the 6.12% from the Ibbotson Supply Side approach, the OCC's survey recommendation of 5% and the combination of the Company's 10.21%, 10.05% and 8.31%, to estimate the equity risk premium. These values are weighted equally for an Authority estimate of 6.88% representing the (R_m – R_f) calculation. Applying the Authority's assumptions using the simple CAPM formula (3.845% R_f + 0.75 B [6.88% R_m – R_f]), resulted in CAPM equity cost rate of 9.03**%** for the Authority Peer Group.

iii. Analysis of the Risk Premium Model

The Authority also reviewed the risk premium method employed by the Company. Mr. Hevert's risk premium method shows that the proxy for the utilities' cost of equity were the returns authorized by state commissions for the years from 1980 through 2014 and the respective Treasury yields for those periods. The resulting risk premium is applied to three different projected Treasury yields. The Authority notes that the OCC did not perform a utility risk premium and this method was not used in the cost of equity estimation process. The Authority concurs with the OCC that using the allowed authorized returns as a proxy for the return on the stock market reflected utility commission behavior. Jurisdictionally-allowed returns should not be relied upon as a proxy from a cost of capital approach, this should be market based and reflect investor behavior. The Authority finds that to allow utility state commissions' authorized ROEs to serve as a proxy for the stock return portion of a risk premium approach is to allow a non-market based estimate to serve as a proxy for the market's return. Cost of capital methods need to be market based. Therefore, the Authority rejects the Company's proposed risk premium method in total.

f. Flotation Costs

According to the Company, an adjustment to the ROE to include flotation costs is appropriate to not only reflect current or future financing costs, but also to compensate investors for costs incurred for all past issuances comprising the total equity portion of the Company's capitalization and are part of capital costs. Flotation costs are the costs associated with the sale of new issues of common stock and are part of capital costs. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance. Since flotation costs are incurred over time, the majority of flotation costs are incurred prior to the Test Year, but remain part of the cost structure during the Test Year and beyond. Mr. Hevert stated that recovery of flotation costs is appropriate even if no new issuances are planned in the near future because failure to allow such cost recovery may deny the Company the opportunity to earn its required

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[23] *See* Decision dated August 14, 2013 in Docket No. 13-01-09, p. 137; and 2009 CL&P Rate Case Decision, p. 109.

rate of return in the future, thereby diminishing its ability to attract adequate capital on reasonable terms. Hevert PFT, pp. 49–52.

To calculate a flotation adjustment, Mr. Hevert modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. Mr. Hevert gathered the two most recent open market common stock issuances for each member of the proxy group to determine the amount of flotation cost incurred for each issuance and then divided those costs by each proxy company's expected dividend yield. As shown in Hevert Exhibit RBH-14, Mr. Hevert arrived at an adjustment of 0.14% or 14 basis points as a reasonable representation of flotation costs for CL&P. Although Mr. Hevert claimed that a flotation cost adjustment of 14 basis points is appropriate, he is not proposing an upward adjustment to his recommended ROE of 10.20%. Instead, Mr. Hevert considered the effect of flotation costs, in addition to the Company's other business risks, in determining where CL&P's ROE falls within his range of results. Hevert PFT, pp. 51 and 52, Exhibit RBH-14.

The OCC argued that an upward adjustment to CL&P's equity cost rate for flotation costs is not warranted. The OCC contends that this adjustment factor is erroneous for several reasons. To start, the Company had not identified any test year flotation costs for CL&P. Foremost, it is commonly argued that a flotation cost adjustment is necessary to prevent the dilution of the existing shareholders. In this case, the Company justifies an adjustment by referring to the manner in which issuance costs are recovered by including the amortization of bond costs in annual financing costs. Dr. Woolridge points out that the Company's justification for recovery of flotation costs is incorrect for several reasons. First, market-to-book ratios for the electric industry trade above 1.5x, which suggests a flotation cost reduction. Second, a flotation adjustment would be needed only in the event the market price of the stock was at/or below its book value. Third, flotation costs are primarily underwriting spreads or fees and not out-of-pocket expenses. It is the offering price, not the price the Company receives which matters to the market; therefore, the Company should not get an adjustment to the allowed return. Fourth, flotation costs would be best viewed as a transaction expense to access the capital markets. Although, CL&P wanted to be compensated for these transaction costs, the Company had not accounted for other transaction costs in determining the cost of equity, such as brokerage fees investors pay. If the Company considered brokerage fees in the DCF analysis, the stock prices would be higher and the dividend yield would be lower. This would lower the effective cost of equity. Woolridge PFT, pp. 74–76.

Mr. Hevert disagreed with Dr. Woolridge's observation that underwriter fees are not out-of-pocket expenses and that flotation costs could represent a reduction in cost of equity. Mr. Hevert disputed that the distinction is not meaningful whether fees are paid directly or through an underwriting discount, the cost results in net proceeds that are less than gross proceeds. Also, Mr. Hevert maintained that flotation costs are true and necessary costs to the issuer, and to the extent flotation costs are not recovered, the issuing company is denied a portion of the opportunity to earn its required return. Hevert Rebuttal Testimony, pp. 59 and 60.

The Authority concludes that the allowance for flotation costs is reviewed on a case by case basis. Mr. Hevert calculated a 14-basis point adjustment to reasonably represent flotation costs for CL&P, and the Authority will incorporate the 14 basis point adjustment for flotation cost in this Decision.

g. Financial Condition and Other Economic Factors

The Authority analyzed a considerable breadth of information presented in this proceeding in order to determine the appropriate return on equity to allow CL&P. Examining the testimonies, record evidence, various approaches and methodologies, as well as the financial and economic factors, the Authority is unable to substantiate maintaining the Company's currently allowed ROE of 9.40%, much less increase the ROE as proposed by CL&P. This is attributable to both the technical analysis and a variety of changes in key factors surrounding the financial setting of such a ROE. The Authority's review of the record evidence also focused on the economic and financial changes since the 2009 CL&P Rate Case, the 2012 merger of NU with NSTAR, recently awarded ROEs in Connecticut, the application of the cost of capital methods proffered by the Company and the OCC witnesses, and the Authority's assessment of each witness' recommendations and its own application of the cost of capital models as applied to the financial data in the record.

The Authority reviewed the changes to several financial and economic indicators to take account of the economic trends that have occurred since the Company's last rate case approximately four years ago. There have been several noteworthy changes in this span of time. The first is the economic recession that began in the third quarter of 2008 which resulted in steep declines to the stock market, real estate market, and dramatic increases in the number of unemployed and underemployed workers. In response to the recession, the Federal government intervened to support the banking and auto sectors in the form of bailouts, as well as to provide injections of money to state government to assist in stimulating the economic recovery. Since the time of CL&P's last rate proceeding, the Federal Reserve's asset purchases under its Quantitative Easing Policy (Federal Monetary Policy) began putting more liquidity in the market and yields fell again resulting in a higher valuation of utility stocks. The quantitative easing Part 3 of the Federal Monetary Policy began in September 2012, and is thought to have a high correlation on utility price earnings ratios. Tr. 9/10/14, pp. 1810 – 1815. The accommodative, cheap money policies and resultant low interest rate environment of the Federal Reserve Bank continue to preside, though there is discussion that these policies will likely taper off and gradually reverse should the national unemployment rate reach 6.5%.

The Company provided the following financial and economic statistics related to Gross Domestic Product (GDP), Consumer Price Index (CPI), unemployment, U.S. Treasury rates and other relevant information covering the changes in these from the time of its last rate case through the most recent quarter. This information is contained in the table below:

Table 62

Financial/Economic Indicator	2009	2013	2014 (latest day, month or quarter)*	Change 2009 to 2013	Change 2009 to Present
Gross Domestic Product (Trillions)	14,417.9	16,799.7	17,101.3	16.52%	18.61%
Consumer Price Index (CPI)	214.54	232.96	232.07	8.59%	8.17%
Unemployment Rate (National)	9.28%	7.35%	6.30%	(1.93%)	(2.98%)
Unemployment Rate (Connecticut)	8.21%	7.76%	6.90%	(0.45%)	(1.31%)
U.S. Treasury Bills (90-day)	0.15%	0.06%	0.03%	(0.09%)	(0.12%)
U.S. Treasury Bills (180-day)	0.28%	0.09%	0.06%	(0.19%)	(0.22%)
U.S. Treasury Bonds (10-year)	3.26%	2.35%	2.63%	(0.91%)	(0.63%)
U.S. Treasury Bonds (20-year)	4.11%	3.12%	3.18%	(0.99%)	(0.93%)
U.S. Treasury Bonds (30-year)	4.08%	3.45%	3.45%	(0.63%)	(0.63%)
State Allowed ROE's for utilities	10.48%	10.02%	10.23%	(0.46%)	(0.25%)
Market-to-book ratios for Industry	1.56	1.79	1.98	14.98%	27.08%
Market-to-book ratios for Peer Group	1.37	1.63	1.77	18.25%	28.73%
Dividend Yield NU	4.13%	3.47%	3.39%	(0.66%)	(0.74%)
Dividend Yield-Industry Average	4.69%	3.83%	3.42%	(0.86%)	(1.27%)

CL&P Response to Interrogatory FI-66.

Since CL&P's last rate case, it appears that the U.S. economic growth has out-paced the increase of inflation as indicated by the increase in the GDP of 18.61% while inflation as measured by the CPI only increased by 8.17%. However, the interest rates and long-term utility bond yields remain at historical low levels and are below the levels existing at the time of the Company's last rate case. Even with the strong growth seen in the GDP, interest rates remain at historically low levels. Overall, the sluggish economy and relative uncertainty still remains and is also expressed in the continued downward trend of the state authorized ROE's for utilities. Typically, the Authority would incorporate the downward trend in the 30-year long-term U.S. Treasury yields of 63 basis points to the Company's last allowed ROE of 9.40% to calculate an updated ROE of 8.77%. Although there are some signs of improvement in the economy, such as unemployment easing off its highs during the height of the recession, unemployment still remains high at 6.60% nationally and 6.90% in Connecticut. Achieving a 6.5% national rate of unemployment, which could trigger the Federal Reserve to slow its pace or reverse its accommodative monetary policy, would be highly desired but still remains ambiguous that it will occur in the near future.

The economic outlook, now for several years, has promised economic recovery and the rise of interest rates which have not occurred. It can be assumed that as the U.S. economy strengthens with the GDP growing at a rapid pace and interest rates steadily rising, cost of capital should moderately increase. However, it is not clear when, or even if, improvement in economic activity will occur. Even with the Federal Reserve market intervention known as the Quantitative Easing Policy Part 3 expected to taper off in a few months, the Open Market Committee reserves the right to change the pace of its tapering so it is uncertain exactly when or if it will finish. It is reasonable to assume that any impact of the Federal Monetary Policy on the utility stock prices and the relative valuations will persist over time. Therefore, it is probable that the current economic condition that some suggest is a market anomaly, is the "new normal," and interest rates and capital costs will remain low over the next few years. Until there are dramatic improvements in the economy, it is reasonable to assume that these lower estimated returns will persist as long as the low equity cost environment exists.

The average ROEs for the electric and gas industries continue to trend downward as seen by the quarterly publications released by Regulatory Research Associates (RRA), Major Rate Case Decisions. At the time CL&P's last ROE was set at 9.40%, the annual average allowed ROE for the electric industry was 10.48% for 2009. For the calendar year 2013, the national average electric equity return authorized by state commission was 9.8%. This figure has further declined to 9.72% for the first six months of 2014. The Authority notes that the national average electric equity returns would still include those vertically integrated utilities that would hold a higher general risk profile than CL&P which would drive the average ROE higher. As indicated in the exhibit submitted by the OCC witness, in 2013 to 2014, there have been no authorized ROEs of 10% or higher, and the average for the distribution-only electrics is 9.48%. Woolridge PFT, p. 74 and Exhibit JRW-12. This further implies that a decrease in the ROE is warranted in this proceeding. As stated previously, commission-awarded ROEs are not purely market driven outcomes and while instructive, are not solely relied upon from a cost of capital approach.

In addition to the continued decline in authorized ROEs for electric utilities in other states' commissions, the Authority also conducted a review of Connecticut rate case Decisions since the 2009 CL&P Rate Case which allowed 9.40%. The Authority notes that these lower allowed returns transcend to other utilities as well. For example, in the Decision dated August 14, 2013, in Docket No. 13-01-19, the Authority allowed a 9.15% ROE. In Decision dated January 22, 2014, in Docket No. 13-06-08, the Authority allowed a 9.18% ROE. In the Decision dated September 24, 2013, in Docket No. 13-02-20, the resulting ROE was 9.13% excluding a water utility specific 50 basis point bonus. By the Decision dated June 29, 2011, in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules, a 8.83% ROE was granted. In the Decision dated July 14, 2010, in Docket No. 09-12-11, Application of Connecticut Water for Amended Rates, a 9.75% was granted. Likewise, in the Decision dated July 17, 2009, in Docket No. 08-12-07, Application of The Southern Connecticut Gas Company for a Rate Increase, a 9.26% ROE was granted. Given these awarded ROEs in Connecticut since 2009, the range of reasonableness is 8.83% to 9.75%, with those awarded recently in 2013 and 2014 averaging 9.15%.

The Authority also contrasts the Company's recommended ROE of 10.20% to the current economic trends and recently awarded ROEs. In reviewing the full list of all utility rate cases, in which, the Company's witness provided expert cost of capital testimony, Mr. Hevert's recommended ROE has been much higher than the actually allowed ROE awarded in every case. CL&P Response to Interrogatory FI-65. Mr. Hevert testified that it is fairly unusual for a commission to adopt any one witness' ROE. Tr. 9/10/14, pp. 1766 – 1769. Upon closer inspection of 16 of the most recent cases where Mr. Hevert provided expert testimony, all of the final authorized ROEs were below Mr. Hevert's recommended ROE ranges. Late Filed Exhibit No. 35. In fact, in this proceeding, the Authority finds that Mr. Hevert's recommended ROE range of

10.20% to 10.70% is well outside even his own results. Out of the 81 total estimates computed by the Company, only 11 of those estimates fell within Mr. Hevert's recommended ROE range for CL&P. Tr. 9/10/14, pp. 1804 – 1808.

According to Conn. Gen. Stat. §16-19tt (Decoupling Statute) and later amended with the passage of P.A. 13-298, An Act Concerning the Implementation of Connecticut's Comprehensive Energy Strategy (the Act), the Authority may consider the impact of decoupling and make any necessary adjustments to the ROE to account for a full decoupling of electric revenues from customer usage. The Authority concurs with the AG that the implementation of a decoupling mechanism further mitigates the earnings pressure of the Company having the impact of reducing the overall risk profile of CL&P. However, the record evidence does not support or quantify a specific adjustment to the ROE to account for decoupling. In fact, neither the Company nor the OCC witnesses suggested an adjustment to their recommended ROEs to quantify an impact for decoupling. These revenue stabilization mechanisms have become common in the industry and among the peer group companies selected in this proceeding. The Authority finds that revenue stabilization and cost recovery mechanisms, such as decoupling, are already reflected in current market valuations of the proxy companies. Although the Authority did not explicitly make a downward adjustment to the ROE to account for a decoupling mechanism, it confirms that a lower ROE is appropriate in this proceeding.

i. Credit Rating and Financial Metrics

From a financial viability perspective, CL&P's credit ratings and financial metrics have improved since the 2009 CL&P Rate Case. Even more significantly, the successful integration of the merger of NU and NSTAR in April 2012, momentously impacted CL&P's business and financial risk profiles and overall positive outlook by the financial community. Both S&P and Fitch upgraded CL&P's ratings due to the merger between NU and NSTAR. Since the 2009 CL&P Rate Case, the Company has increased its S&P bond rating from BBB to the present A-, two notches. As of June 24, 2014, the Company has credit ratings of A- (outlook: Positive), Baa1 (outlook: Stable), and BBB+ (outlook: Stable) from S&P, Moody's and Fitch, respectively. CL&P Response to Interrogatory FI-74. CL&P also testified that the Company is at least one notch above the average for the rest of the proxy companies. Tr. 9/10/14, pp. 1829-1832.

The Company expects to maintain its creditworthiness. The rating agencies consider a variety of factors including the regulatory environment, credit metrics such as strength of capital structure, allowed returns, earnings and cash flows in assigning ratings to any given company. The Company's S&P ratings have steadily improved in recent years as a result of NU's improved consolidated financial risk profile along with its excellent consolidated business risk profile, continued focus on controlling costs and customer service. On April 25, 2014, S&P affirmed the corporate credit ratings and revised outlooks to positive from stable of NU, CL&P, NSTAR Electric, PSNH, WMECO, Yankee Gas and NSTAR Gas. CL&P Interrogatory Response to FI-53. For Moody's, evaluation of key financial metrics such as debt measurements and liquidity in earnings measurements approximates 40% of its ratings factors, while the recovery of costs and earning allowed returns account for approximately 25% of its ratings factors. The remaining 35% are qualitative factors, such as regulatory framework and diversification. CL&P Response to Interrogatory FI-75.

According to S&P's Research Report dated April 30, 2014, S&P's positive outlook for the Company reflects the view of NU's successful merger integration. Because CL&P is a core subsidiary of NU, the positive outlook on CL&P mirrors that of NU and reflects NU's successful merger integration and effective management of regulatory risk. CL&P Response to Interrogatory FI-75. The Company has improved its financial measures due in part to the successful merger integration. From a credit perspective, recovery of the bulk of storm costs through the PURA's Storm Cost Recovery Decision is favorable as it eliminates a considerable degree of uncertainty. Overall, CL&P's business risk is viewed as excellent due in part to its low-risk regulated electric distribution and transmission operations, predictable revenue stream and efficient operations. Id.

The Company supplied key financial metrics on a consolidated basis valued at year end, December 31st, which are compiled in the table below. The forecasted figures for year-end 2014 through 2018 were filed as confidential.

Table 63

Ratio	2009	2010	2011	2012	2013
Total Asset Turnover	40.9%	36.3%	29.0%	26.3%	27.2%
Current Ratio	122.9%	106.2%	69.2%	70.9%	63.5%
Cash Flow from Operations	120.7%	99.9%	52.5%	23.0%	45.4%
Total Debt to Total Capitalization	50.9%	50.7%	51.4%	52.7%	51.8%
Times Interest Earned	3.15x	3.73x	3.56x	3.28x	4.15x
Fixed Coverage Ratio	3.05x	3.59x	3.42x	3.17x	4.01x
Cash Flow Coverage Ratio	4.3x	5.1x	3.9x	1.6x	3.7x
Operating Margin	N/A	N/A	N/A	N/A	N/A
Profit Margin	6.3%	8.1%	9.8%	8.7%	11.4%
Contribution Margin	N/A	N/A	N/A	N/A	N/A
Return on Total Assets	5.87%	6.23%	5.38%	4.78%	6.18%
Return on Total Capital	2.02%	0.52%	0.13%	1.94%	2.18%

CL&P Response to Interrogatory FI-70.

CL&P has been able to improve many key financial measures from the period ending 2009 through 2013 as indicated in the table above. Since 2009, the Company shows a stronger times interest earned ratio, fixed coverage ratio, profit margin, return on total assets and return on total capital. Although the Company's cash flow coverage, total asset turnover and cash flow from operations ratio declined since 2009, these financial ratios rebounded and significantly improved from 2012. The Company will continue to maintain its financial strength as CL&P forecasts robust financial metrics through 2018.

In general, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses, due to the essential nature of their services as well as their regulated status. Although the overall outlook for the economy as a whole has a great deal of uncertainty and recovery has been sluggish, CL&P has been successful in navigating the credit markets due to its healthy and stable financial condition. Investment risk of public utilities is still relatively low compared to the market as a whole (1.0 beta) as evidenced by the drop in NU's beta from .80 in 2009 to .75 currently. CL&P continues to maintain a strong financial position, limited risk profile, visible forward earnings stream, a stable dividend yield, strong balance sheet and strong cash position. Despite the decline in interest rates, utilities continue to outperform most sectors of the bond market. As such, the cost of equity for the electric industry is among the lowest of all industries in the U.S. All these indicators discussed above, including the technical analysis and current market conditions, suggest a decline in the overall equity cost rate while allowing CL&P to retain its financial viability.

h. Response to Written Exceptions on Cost of Equity

In its Written Exceptions, CL&P claims that the decision to authorize an ROE of 9.17 percent is improper because it was determined using: 1) a separate "cost of equity analysis" prepared by the Authority and not subjected to review in the hearing phase of this proceeding; 2) non-record evidence, 3) factually incorrect evidence; as well as 4) "positions and evidence" gathered in an unresolved PURA docket that was closed without a Final Decision being issued. CL&P Written Exceptions, pp. 6 and 7. For these reasons, CL&P requests that the Authority reject its cost of equity analysis and set the authorized ROE at the national average of 9.48%. CL&P Written Exceptions, p. 18.

Essentially, CL&P claims that the Authority committed legal errors in setting the ROE of 9.17%by using the same method the PURA used to determine the ROE level in the UI, CNG and Aquarion rate cases and by not formally taking judicial notice of 11 publicly available data sources and 1 data source available by subscription which were data identified in Interrogatory FI-67 directed to CL&P. The Authority has routinely reviewed these data sources in past rate case proceedings, including the UI, CNG and Aquarion rates cases, and has relied on this data in past Decisions for determining ROE levels.[24]

Specifically, CL&P claims that the Authority erred by relying on certain evidence that was not administratively noticed and applying an ROE calculation methodology other than the one offered by its or the OCC's experts. CL&P claims the Authority deprived CL&P of its statutory right under Conn. Gen. Stats §§4-177c(a) and 4-178(5) to conduct cross-examination and submit rebuttal testimony to all of the evidence the PURA relied upon, including the right to cross-examine and rebut (through the use of its own witnesses) the data the Authority relied upon in its decision-making process. CL&P claims that the Authority deprived the Company of its right to cross-examine and rebut evidence because the PURA failed to properly take administrative notice of facts it

[24] Docket No. 13 06-08, Application of Connecticut Natural Gas Corporation to Increase Its Rates and Charges, Decision dated January 22, 2014, Section II.F., pp. 65-109; Docket No. 13-02-20, Application of Aquarion Water Company of Connecticut for Amended Water its Rates, Decision dated September 24, 2013, Section II.K., pp. 74-116; Docket No. 13-01-19, The United Illuminating Company's Application to Increase Rates and Charges, Decision dated August 14, 2013, Section II.G., pp. 87-139.

relied on in its ROE analysis. Conn. Gen. Stat. §4-178 and the Regulations of Connecticut State Agencies §16-1-38(d) and (e).

As discussed in detail below, all of the data sources relied on by the Authority were contained in the evidentiary record of this proceeding. Additionally, analyses of record evidence produced by this decision-making process after the initial evidence gathering step are not themselves evidence and do not entitle a party to cross-examine their authors and rebut their accuracy. Connecticut Natural Gas Corp. v. Public Utilities Control Authority, 183 Conn. 128, 136-143 (1981). Authority staff may also advise the Commissioners regarding the appropriate methods of ROE analysis to use in its consideration of the Application. The Authority is not required to base its Decision on expert testimony offered by the applicant or other parties' experts if the Authority determines, based on its knowledge and expertise, that another method is reasonable and more appropriate. Moreover, the Authority, as an expert regulatory agency, may treat the testimony of expert witnesses as to which conclusions they would draw from facts of record as mere argument, which, if reasonable, may help the agency arrive at its Decision, and the Authority may disregard the expert testimony if it is contrary to its knowledge or experience. Thus, CL&P's expert opinion testimony regarding the appropriate evidence and analysis to rely for calculating the Company's ROE does not bind the Authority. Id.

With respect to which method to employ to review and set CL&P's ROE, the Authority has broad discretion. The PURA's enabling statute evinces a legislative intent to rely on the Authority to regulate and supervise public utilities, and to establish rates that are not unreasonable. The legislature, however, has not imposed upon the Authority any specific formula or policy to use in setting rates. In view of the remedial purpose of the statute, the lack of an express statutory formula and the evident legislative intent to rely on the Authority's expertise, the Connecticut Supreme Court concluded that the language of the enabling statute is sufficiently flexible to permit the Authority to create necessary policies to guide its rate-making decisions. Greenwich v. Department of Public Utility Control, 219 Conn. 121, 124-127 (1991); Office of Consumer Counsel v. Dep't of Pub. Util. Control, 2005 Conn. Super. LEXIS 1174, Superior Court of Connecticut, Judicial District of New Britain at New Britain, Docket No. CV040528294S, Memorandum of Decision dated April 26, 2005, Robert F. McWeeny, J., pp. 6-10. The Connecticut Supreme Court also found that "Rate-making bodies (are not bound) to the service of any single formula or combination of formulas. The agency to which the legislative power has been delegated is free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances." Greenwich at footnote 4 citing Power Commission v. Pipeline, Co., 315 U.S. 575, 586 62 S. Ct. 736, 86 L. Ed. 1037.

CL&P had notice of the ROE methodology that the Authority applied in this proceeding to determine the Company's ROE. The Authority finds that the methodology it applied to determine CL&P's ROE of 9.17 percent is supported by past precedent in the CNG, Aquarion and UI rate cases[25] where the Authority applied the same

[25] Docket No. 13 06-08, Decision dated January 22, 2014, Section II.F., pp. 65-109; Docket No. 13-02-20, Decision dated September 24, 2013, Section II.K., pp. 74-116; Docket No. 13-01-19, Decision dated August 14, 2013, Section II.G., pp. 87-139.

methodology in setting the ROEs for those companies. The Authority developed its current ROE methodology based on comments and evidence submitted in Docket No. 09-10-06, Investigative Inquiry into the Desirability, Need and Feasibility of Establishing a Uniform Methodology for Determining Return on Equity (2009 Generic ROE Proceeding), which the Authority cites to provide guidance and clarity to parties regarding the PURA's approach to its cost of equity analysis. The purpose of referencing the 2009 Generic ROE Proceeding is to show consistency and transparency among the Authority's analysis in each rate proceeding in which the methodology has been applied.

The Authority also finds that its use of the data from particular data sources is also supported by the record and by precedent of the PURA using that data in past rate Decisions, including CL&P's last rate case.

The record supports the Authority's use of the 12 sources of financial data it relied on to determine the ROE. The Authority asked in Interrogatory FI-67, if CL&P objected to the Authority considering the following data sources, commonly relied on by finance experts, as part of the record:

a) Recent and historical US Treasury Rates (90 day, 180 day, 10 year, 20 year and 30 year) as reported in the Wall Street Journal and online at:
   1. www.bankrate.com/brm/ratewatch/leading-rates.asp
   2. www.ustreas.gov/offices/domestic-finance/debt-management/interest-rate
   3. www.finance.yahoo.com
b) Latest Mergent Bond Guide.
c) Latest Value Line: Electric Industry Group, East, Central & West editions.
d) Latest Value Line: Summary and Index.
e) Latest Blue Chip Economic Indicators edition through end of proceeding.
f) Latest Blue Chip Economic Forecast edition through end of proceeding.
g) Latest AUS Monthly Utility Reports.
h) Ibbotson Associates, Stocks, Bonds, Bills and Inflation (SBBI) 2014 Yearbook, Morningstar Inc., 2014 edition. Including Basic Series exhibit and Determination of the Discount Rate exhibit.
i) Stock prices from www.finance.yahoo.com for companies included in proposed company peer group.
j) EPS growth estimates from www.money.msn.com for companies included in proposed company peer group.
k) EPS growth estimates from www.finance.yahoo.com for companies included in proposed company peer group.
l) EPS growth estimates form www.zacks.com for companies included in proposed company peer group.

With the exception of the Mergent Bond Record, all sources of financial data have been provided on the record and/or were publicly accessible through their Internet domains.[26] The Authority notes that the Mergent Bond Record was only relied on to

[26] *See* CL&P responses to Interrogatories FI-86, FI-87, FI-88, FI-90, FI-94,FI-95 (Bulk Filing), OCC-243, OCC-244, OCC-245 and OCC-246. Hevert PFT, Exhibits RBH-1 through RBH-15. Hevert Rebuttal

elevate the threshold to screen out those low DCF results. By removing this data source from the record, therefore eliminating the DCF screening, has the effect of decreasing the DCF ROE estimate from 9.03% to 8.47%. As explained previously in more detail, the Mergent Bond Record was used to obtain the average bond yield for each company in the proxy group. The Authority increased the minimum threshold which eliminated numerous companies that had very low DCF results, thereby increasing the average DCF ROE result.

Through Interrogatory FI-67, the Authority provided CL&P with actual notice of the data sources the Authority intended to rely on in analyzing the ROE and gave CL&P an explicit opportunity to object. In response to Interrogatory FI-67, CL&P stated that it had no objection to any of the sources listed, except the AUS Monthly Utility Reports. CL&P objected to AUS Monthly Utility Reports because "[t]he information they compile is available reliably from other listed sources, and therefore CL&P would object on this basis to PURA taking administrative notice of these reports." Response to Interrogatory FI-67. If CL&P had objected on the basis that the AUS Monthly Utility Report data was inaccurate, in some manner unreliable, or not accepted as a reliable source in the finance expert community, the Authority may have examined this objection further by cross examining CL&P's expert witness during the hearing. CL&P has not objected to the AUS Month Utility Reports on any of such basis. To the contrary, CL&P agrees that these sources of financial data are broadly published and generally used for industry purposes. These sources of financial data have been used reliably by cost of capital experts and the Authority in rate proceedings. CL&P Written Exceptions, p. 9.

The Authority finds that CL&P waived the right to object to any of the other sources cited to in FI-67.[27] The Authority also finds that CL&P is not harmed if the Company is merely claiming that the AUS Monthly Utility Report may provide repetitive or redundant data already contained in the other sources. Based on the foregoing, the Authority overrules CL&P's objection to use of the AUS Monthly Utility Reports.

Additionally, use of the data CL&P now objects to in its Written Exceptions is supported by Authority precedent in past rate Decisions. CL&P cannot now claim ignorance or surprise regarding the Authority's reliance on those data sources to determine ROE levels. For example, the Mergent Bond Guide which CL&P objects to the Authority using in its analysis was relied on by CL&P's witness and examined by the Authority in CL&P's 2010 Rate Case Decision[28] and was used by the Authority in the CNG and UI rate cases.[29] Moreover, by virtue of the Authority's Interrogatory FI-67,

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PFT, Exhibits RBH-1 through RBH-20. OCC responses to Interrogatories CL&P-2 (Bulk Filing on CD), CL&P-3, CL&P-4, CL&P-5, FI-182, FI-185 and FI-186. Woolridge PFT, Exhibits JRW-2 through JRW-14. Tr. 9/10/2014, pp. 1768 – 1771, 1779 – 1783, 1785 - 1788, 1790 – 1799, 1815 – 1817, 1822 – 1823, 1844 – 1845, and 1863 – 1865. See also, Transcript of Oral Arguments held on December 12, 2014, for numerous references to the record made by the OCC and AG during their oral arguments.

[27] In its Written Exceptions, CL&P objects to the Mergent Bond Guide for the first time on the basis that is a subscription service that is not publicly available. The Mergent Bond Guide was relied on by CL&P's witness and examined by the Authority in CL&P's 2010 rate case. Docket No. Docket No. 09-12-05 Decision, p. 97.

[28] Id.

[29] Decision dated January 22, 2014 in Docket No. 13-06-08, ; Docket No. 13-02-20, Decision dated September 24, 2013; Decision dated August 14, 2013 in Docket No. 13-01-19pp. 109, 117 and 130.

CL&P had actual notice that the Authority was going to examine and use recent data from these sources. The AUS Monthly Utility Report that CL&P objects to was also used by the Authority in the UI, CNG and Aquarion rate cases.[30]

The Authority finds that there is no merit to CL&P's claim that a "lack of a proper introduction of evidence into the record affects the computation of the ROE adopted by the Authority in the Draft because the product of the "Authority's Analysis" are the low-side values skewing the ROE to 9.17 percent." The ROE of 9.17 percent was not affected by how data sources were introduced in the record. Rather, the ROE of 9.17 percent was the correct result produced by analysis which properly took into account a full set of appropriate data sources.

Finally, CL&P did not in response to Interrogatory FI-67 or now in its Written Exceptions object on a substantive basis to the Authority's use of any data, (i.e. that data is inaccurate, the data is not reliable, the data is not the correct type of data, etc.) CL&P now sees the specific data points relied on by the Authority and has provided no substantive reason for why any of the data points should not be considered by the Authority in setting the ROE. CL&P's objection is purely procedural. CL&P, through its Written Exceptions, has been provided an opportunity to impeach, discredit or otherwise explain why the data or data sources relied on by the Authority in its ROE analysis should not be used because it is somehow flawed, inaccurate, not accepted within the financial community, etc. CL&P offered no such claims in response to Interrogatory FI-67 or in its Written Exceptions, but rather seeks to preclude the Authority from using otherwise appropriate, relevant, material and probative data based on claims of procedural harm. There is no evidence of actual procedural harm to CL&P since it had actual and constructive knowledge that the Authority would rely on recent versions of these data sources. Based on Interrogatory FI-67 as well as the Authority's recent rate case decisions for CNG, UI and Aquarion, CL&P had actual and constructive notice that the Authority would review and probably rely on these data sources to set the ROE. The Authority further finds that CL&P suffered no actual prejudice due the fact that all but one of the sources is publicly available.

In its Written Exceptions, CL&P claims that there are three components that are legally and factually deficient and cannot be relied upon. CL&P Written Exceptions, pp. 11 and 12. First, CL&P claims that the value of 8.77% as an update to the last rate case is nowhere in the record and has not been presented for review or cross examination. As indicated previously in the Decision, the 8.77% simply reflects the decline in the 30-year long-term U.S. Treasury yields of 63 basis points to CL&P's last allowed ROE of 9.40% (9.40% - 0.63% = 8.77%). The Authority typically makes this simple calculation to use as another benchmark or parameter to indicate in which direction the current allowed rate should trend. Although the drop in the interest rates is much more pronounced than the decline of the state authorized ROEs, the overall downward trend in returns is evident. This benchmark was also used by the Authority in the recent UI and CNG rate case Decisions.

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[30] Decision dated January 22, 2014 in Docket No. 13-06-08, p[p. 68 and 70; Decision dated September 24, 2013 in Docket No. 13-02-20, pp. 82, 91, 99 and 115.

Second, the Company claims that the statements made in the draft that a 6.5% national rate of unemployment and a change in Federal Reserve policy to reverse its monetary policy would be highly desired but still remains ambiguous that it will occur in the near future, are factually incorrect. CL&P Written Exceptions, pp. 12 and 13. The Authority finds that these statements are correct and refers the Company to review the lengthy discussions cited in the transcript.[31] At the time the Authority drafted this Decision and the record was closed, it was still unknown if or when the Federal Reserve would reverse its accommodative monetary policy. The Authority agrees that the steady decline in the national unemployment and the reversal of the Federal Monetary Policy is highly desirable and supports an improvement in the economy. However, as the Authority stated in that section of the Proposed Final Decision, there are also other indicators such as continued decline in interest rates, low long-term bond yields, downward trend of the state authorized ROEs for utilities, and the relative uncertainty still remains.

Lastly, the Company contends that the DCF and CAPM analysis computed by the Authority used financial data not on the record for the proceeding and the entire computational analysis not made available to the Company or other parties in this proceeding. CL&P Written Exceptions, p. 13. As discussed above, the Authority finds that its use of the sources of financial data is clearly supported by the record, as well as precedent of the Authority using that data in past rate Decisions. Without a specific reference by CL&P to the computational analysis, the Authority finds that the record is clear regarding the PURA's computations based on the narrative description regarding the process, methods, computation and sources of financial data used in the Authority's analysis.

The Company's request that the Authority reject the proposal in the Decision and set the authorized ROE at the national average of 9.48% is unreasonable. Since the ROE is a market-based concept, jurisdictionally allowed returns should not be relied upon as a proxy from a cost of capital approach. To simply ignore all the relevant financial data and current market analysis compiled by all the cost of capital witnesses in this proceeding, is not keeping with the fundamental standards that returns should be commensurate with the returns expected of enterprises having comparable risks. The Authority's analysis is reflective of the record and corresponds as closely as possible to the current market conditions and expected returns.

i. Conclusion on Cost of Equity

In determining the cost of equity, the Authority considered all of the witnesses' cost of equity analyses by integrating some of the methods in its own evaluation. Consistent with past practice, the Authority relies on the results of the constant growth DCF and simplified CAPM methods in its analysis. Typically, the Authority weighs the DCF model more heavily in its analysis. However, in this case the weighting of the methodologies had no influence on the final result since the DCF and CAPM estimates were identical. The Authority also used its analysis that updated the last Company rate case and the survey of recent Decisions merely to establish benchmark parameters and

[31] See Tr. 9/10/14, pp. 1810 - 1815.

to indicate in which direction the current allowed rate should trend. The Authority has not incorporated an explicit downward adjustment to ROE for the implementation of a full decoupling mechanism, given that the majority of its peer companies have some form of a revenue stabilization cost structure embedded into their cost of equity valuations. The Authority recognizes that these mechanisms reduce the risk of the Company and contribute to lower expected returns. Consequently, in regulating CL&P to allow a return commensurate with the current economic conditions, the Authority has determined that investors expect less of a return today than in 2010, when the return was established at 9.40%. The Authority finds that the Company has strengthened its financial capability and has less risk, both financially and operationally, which provides further support that CL&P is performing well in an environment that expects lower returns.

The table below represents a summary of the Authority's analyses and findings with respect to the ROE.

Table 64

Method	Authority Result
Update Last Rate Case (decline interest rates)	8.77%
RRA Average Allowed ROE as of June 2014	9.72%
2014 Average Distribution-Only ROE	9.48%
Survey Connecticut Allowed ROEs: Average Awarded in 2013 and 2014	9.15%
DCF	9.03%
CAPM	9.03%
Utility Risk Premium	Not Used
Indicated ROE	9.03%
Adjustment for Flotation Cost	.14%
Allowed ROE	**9.17%**

Based upon the implementation of several of the principles detailed from the 2009 Generic ROE Proceeding, the Authority notes that the methodologies have become more transparent and less "black box." Likewise, the application of the process with the present data has narrowed the range of reasonableness. An ROE of 9.17% is indicated by the analysis and the cost of capital measures employed by the Authority is incorporated into its weighted cost of capital assessed below.

j. Authority's Allowed Weighted Cost of Capital

Consistent with the legal guidelines defined in Conn. Gen. Stat. §16-19e(a)(4), the Authority identified a rate of return on the rate base that is deemed appropriate for the Company's overall capital structure. The Authority has recognized 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.

After study and deliberation of all cost of capital issues presented in this proceeding, the Authority finds that 7.31**%** is a fair rate of return, reflecting a return on equity of 9.17**%**. The table below summarizes the approved capital structure components, capital costs and calculates the weighted cost of capital, including the 9.17**%** assigned ROE, determined by the Authority based upon the 50.38% common equity, 2.01% preferred stock and 47.61% long-term debt capitalization.

Table 65
Allowed Weighted Cost of Capital

Class of Capital	**Ratemaking Percentage**	**Embedded Cost**	**Ratemaking Weighted Cost**
Long-term Debt	47.61%	5.45%	2.59%
Preferred Stock	2.01%	4.80%	0.10%
Common Equity	50.38%	9.17%	4.62%
Total Capitalization	100.00%		7.31%

The Authority finds that these rates, when applied to the rate base found reasonable for the Company, should produce operating income sufficient for the Company to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate its investors for the risk assumed.

4. ROE Penalty

In late August, 2011, Connecticut was struck by Tropical Storm Irene (Storm Irene). In late October, 2011, Connecticut was struck by an early snowstorm (October Snowstorm). Storm Irene and the October Snowstorm (the 2011 Storms) resulted in extensive interruptions to electric service. The Authority opened Docket No. 11-09-09, PURA Investigation of Public Service Companies' Response to 2011 Storms, to investigate the Company's (and other utilities') response to the 2011 Storms.[32] The Decision dated August 1, 2012, in the above captioned proceeding states as follows:

> . . . [t]he Connecticut Light and Power Company's performance in the aftermath of the 2011 storms was deficient and inadequate in the areas of outage and service restoration preparation of personnel, support of its municipal liaison program, development and communication of restoration times to customers, and overall communication to customers, other service providers and municipalities, as to warrant regulatory sanction. In this Decision, the Public Utilities Regulatory Authority also concludes that because of The Connecticut Light and Power Company's failure to obtain adequate assistance in advance of the October 29, 2011 storm, its response to that storm was deficient. Because of The Connecticut Light

[32] Docket No. 11-09-09 was initially opened in September, 2011 to investigate response to Tropical Storm Irene. After the October Snowstorm, the scope was expanded to include that event.

> and Power Company's failure to adequately fulfill its duties imposed by law and to adequately and suitably provide for the overall public interest with regard to these particular areas of performance, the Public Utilities Regulatory Authority establishes in this Decision, a rebuttable presumption that The Connecticut Light and Power Company should have imposed on it, an appropriate reduction to its allowed return on equity in its next ratemaking proceeding as a penalty for poor management performance and to provide incentives for improvement. . . In considering the appropriate reduction to allowed returns on equity in forthcoming ratemaking proceedings and in exercising its jurisdictional approval for recovery of appropriate 2011 storm costs, the Authority will consider and weigh the extent to which CL&P has recognized its shortcomings and taken concrete and measurable steps to embrace the need for aggressive, extensive restructuring of both its attitude toward storm management and establishment of new practices for execution of future storm response.

Decision, p. 1.

The Authority took administrative notice of the record evidence presented in Docket No. 11-09-09 and the following consultant reports prepared in connection with the review of CL&P's storm response as well as the Report of the Two Storm Panel: Witt Associates Report; Report of the Two Storm Panel; Liberty Consulting Group; and the Davies Report. Notice of Taking Administrative Notice dated September 3, 2014.

CL&P stated that there is no basis for sanctioning it for its performance in the 2011 Storms. The Company asserted that it has met every applicable requirement relating to storm performance. The Company also asserts that the Authority's investigations and rulings to date support the fact that CL&P's response to these storms was reasonable under the circumstances. CL&P stated that the reasonableness of its actions can be confirmed in two ways. First, the Authority's Decision dated March 12, 2014 in Docket No. 13-03-23 (March 12, 2014 Decision), did not find CL&P to be imprudent, nor did that Decision disallow any costs related to any of those areas. Second, the evidence described in Bowes PFT, Exhibit KBB-3 demonstrates that CL&P's conduct in these areas was reasonable under the circumstances. Finally, CL&P stated that it has made concrete and measurable improvements in relation to its emergency preparedness and response function, as described in Bowes PFT, Exhibit KBB-4. Bowes PFT, pp. 43-45.

The OCC believes that the Authority should impose a 35 basis point penalty on CL&P for its imprudence in responding to the 2011 Storms. Although the OCC recognizes that CL&P has taken a variety of steps to increase the resilience of its distribution system and otherwise improve its storm response, the OCC argues that an ROE penalty is still appropriate because the Company did not adequately prepare and respond to the 2011 Storms. Furthermore, according to the OCC, the prudence standard requires that a utility's actions must be evaluated within the context of information that was known at the time the actions were taken, not after the utility has had an opportunity to remedy any harm that occurred at ratepayer expense. Finally, the OCC cites evidence submitted in Docket No. 13-04-07, PURA Investigation into Allegations that The Connecticut Light and Power Company Impaired and Impeded

PURA's Investigation of CL&P's Response to the October 2011 Nor'easter, as demonstrating that CL&P deliberately withheld accurate power restoration time estimates from the public. OCC Brief, pp. 33-38.

The AG also believes that the Authority should impose an ROE penalty on CL&P for its performance in the 2011 Storms. The AG notes that the Authority established a rebuttable presumption in its Decision in Docket No. 11-09-09 that CL&P should have imposed upon it an appropriate reduction to its ROE in this rate case. The AG cited to findings in the Liberty Report on the 2011 Storms performance that was submitted by the Authority's consultant in Docket No. 11-09-09, and other extensive record evidence in that docket as confirming the Company's inadequate performance in preparing for and responding to the 2011 Storms. Similar to the OCC, the AG asserted that the Authority should impose an ROE penalty of 35 basis points on the Company for its 2011 Storms response regardless of the subsequent demonstrated improvements, since the penalty was intended to be imposed on that basis. The AG next noted that the Authority has previously imposed financial penalties on other utilities that have exhibited poor management performance, and provides cites to those dockets. Finally, the AG stated that, absent the Company's subsequent improvements, it would have advocated for stronger penalty. AG Brief, pp. 23-30.

In the Decision in Docket No. 11-09-09 and restated in the March 12, 2014 Decision, the Authority indicated that it intended to review, in this rate proceeding, the issue of whether or not CL&P's ROE should be reduced to reflect deficiencies in response to the 2011 Storms. Such a review is appropriate in this rate proceeding as the Authority is charged with setting just and reasonable rates after specifically examining and determining the appropriate level and structure of rates charged customers that shall reflect, along with other considerations: 1) prudent and efficient management of the franchise operation, and 2) that public service companies shall perform all of their respective public responsibilities with economy, efficiency and care for public safety and energy security. Conn. Gen. Stat. §16-19e(a)(3) and (5).[33] The

[33] Conn. Gen. Stat. §16-19e, which governs the Authority's regulation of internal utility management and rate structures, states: 16-19e(a) In the exercise of its powers under the provisions of this title, the Public Utilities Regulatory Authority shall examine and regulate the transfer of existing assets and franchises, the expansion of the plant and equipment of existing public service companies, the operations and internal workings of public service companies and the establishment of the level and structure of rates in accordance with the following principles: (1) That there is a clear public need for the service being proposed or provided; (2) that the public service company shall be fully competent to provide efficient and adequate service to the public in that such company is technically, financially and managerially expert and efficient; ***(3) that the authority and all public service companies shall perform all of their respective public responsibilities with economy, efficiency and care for public safety and energy security,*** and so as to promote economic development within the state with consideration for energy and water conservation, energy efficiency and the development and utilization of renewable sources of energy and for the prudent management of the natural environment; (4) that the level and structure of rates be sufficient, but no more than sufficient, to allow public service companies to cover their operating costs including, but not limited to, appropriate staffing levels, and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable which shall include, but not be limited to, reasonable costs of security of assets, facilities and equipment that are incurred solely for the purpose of responding to security needs associated with the terrorist attacks of September 11, 2001, and the continuing war on terrorism; ***(5) that the level and structure of rates***

Authority has reserved for this proceeding consideration of an ROE reduction related to poor performance in 2011.

In this proceeding, CL&P has the burden of proving both its rate proposal is just and reasonable and that its management of storm-related actions in 2011 and going forward were and are appropriate. Conn. Gen. Stat. §16-22; Decision in Docket No. 11-09-09 and March 12, 2014 Decision. CL&P's customers have a right to expect that CL&P performed in 2011, and will perform in the future, its public service duties in a prudent, efficient, safe and adequate manner. See generally, Conn. Gen. Stat. §§16-11, 16-19e, and 16-20. Part of CL&P's burden of proof in a rate case was to show that it has and will properly fulfill its duties.

Based on its findings in Docket No. 11-09-09, the Consultant Reports and other evidence contained in the record in this proceeding and taking into account CL&P's position that it acted prudently in both storms, the Authority finds that CL&P fell short of reasonably fulfilling its duties with respect to the 2011 Storms. The Authority further finds that CL&P's management needs to work toward eliminating past deficiencies and gross inefficiencies and to demonstrate more "prudent and efficient management" with actual improved future storm preparation response performance at a level at or above good utility practice. Further, the Authority finds that CL&P must not repeat its past deficient level of performance and improve the performance of "public [storm response] responsibilities with respect to economy, efficiency and care for public safety and energy security" at or above the level of acceptable utility practice standards.

Contrary to CL&P's assertions, the Authority concludes that it is not required by Conn. Gen. Stat. §16-19e(a)(3) and (5) to make any explicit findings of past imprudence in order to set the going forward ROE for CL&P. If the Authority were going to disallow cost recovery, the Authority would be required to make a finding of imprudence to support the disallowance. In the Decision in Docket No. 11-09-09 dated August 1, 2014, the Authority specifically tied its discussion of prudency to the issue of CL&P's future recovery of storm-related costs. Decision, Section III.A.3, p. 18. The Authority did not state that the prudency issue or prudency determination had any relevant relationship to the Authority's future determination regarding an appropriate ROE level for CL&P. Decision, Section III.A.4, 18-19.

With respect to setting an appropriate ROE in this proceeding, the Decision in Docket No. 11-09-09 stated that the Authority would examine whether to impose an "appropriate basis point reduction to CL&P's allowed return on equity (ROE) for such poor management performance and to provide incentives for improvement." As CL&P recognizes, the Authority is not ordering the disallowance of storm-response-related cost recovery in this proceeding. Therefore, prudence is not at issue. Instead, the Authority is 1) reviewing the history of CL&P's 2011 storm response performance and CL&P's subsequent actions in that regard; 2) making determinations based on the

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charged customers shall reflect prudent and efficient management of the franchise operation; and (6) that the rates, charges, conditions of service and categories of service of the companies not discriminate against customers which utilize renewable energy sources or cogeneration technology to meet a portion of their energy requirements. [Emphasis added].

factors listed in Conn. Gen. Stat. §16-19e(a)(3) and (5); and, 3) reflecting those determinations in establishing a just and reasonable future ROE level for CL&P.[34]

With respect to Conn, Gen. Stat. §16-19e(a)(3) and (5), the Authority finds that the record evidence from Docket No. 11-09-09 and this docket fully, as described herein, supports the Authority's determination that CL&P's storm response was inadequate and deficient sufficient to warrant implementation of a rate making ROE reduction incentive to signal the need for improved management performance with respect to past and future storm responses. The Authority's consultant, The Liberty Consulting Group (Liberty) found that "CL&P's storm performance was below average." Liberty Report, 1. Liberty cited to failures in CL&P's tree trimming program, its restoration estimates, its management command system, its ability to acquire outside resources and its coordination with towns as all deficient. Liberty Report, 1 and 2. CL&P did not seek meaningful outside resources until after the storm hit and caused numerous service outages. Liberty Report, p. 78; Davies Report, p. 21.

In addition, CL&P's Emergency Response Plan (ERP) did not adequately stress training and drills. Liberty Report, pp. 13 and 18. CL&P employees questioned the plan and its application during the 2011 Storms and suggested that it was written for regulators, was not applied during the 2011 Storms, lacked adequate specificity and that while it may have worked on paper, it was not the subject of adequate training. Liberty Report, pp. 18-19. There is no evidence that CL&P drilled or exercised its ERP for at least five years prior to the 2011 Storms. Witt Report, p. 17.

The Authority finds that there was also substantial evidence in the record of Docket No. 11-09-09 that CL&P's municipal liaisons were poorly prepared, poorly

[34] Notwithstanding this determination, the Authority finds that CL&P's 2011 Storm preparations and responses were imprudent. The Authority applies a three-part test is as follows: "First, there must be a clearly understood definition of the standard of care by which a utility's performance can be measured. Second, the actions of the utility must be examined to determine if there has been a failure on its part to conform to the standard required. Finally, there must be a reasonably close casual connection between the imprudent conduct, if any, and actual loss or damage. Applying this test, the Authority finds that CL&P was imprudent for failing to act as a reasonably prudent utility in the following ways: 1. CL&P inadequately prepared for major storms, and failed to exercise or drill its emergency response plans and evaluate the results for at least five years prior to the storms; 2. CL&P failed to request the assistance of outside crews in a timely manner and failed to reasonably manage the crews that arrived; 3. CL&P engaged in an unreasonable damage assessment process, including failure to transmit assessment information from the field to operations headquarters efficiently; 4. CL&P failed to train and support municipal liaisons and defer to local restoration priorities; 5. CL&P failed to reasonably develop estimated restoration times; and 6. CL&P failed to reasonably manage communications with the public and public officials concerning restoration times. As a result of the aforementioned imprudent conduct, CL&P's customers suffered tangible great economic losses, including but not limited to lost food, medicine, and income and added expenses for hotels and other items purchased to survive the storm and cold weather conditions during outages. CL&P's customers likewise suffered substantial intangible harms, including but not limited to great levels of inconvenience, uncertainty, and discomfort. The Authority finds that the various storm reports contained in the record and the Briefs and Reply Briefs of the AG and OCC filed in this proceeding appropriately describe CL&P's imprudent conducts and the resulting harm to customers. The Authority declines to articulate further on this imprudence finding given that "imprudence" is not a necessary statutory finding for the Authority to make in reducing the ROE pursuant to Conn. Gen. Stat. §16-19e(a)(3) and (5).

supported and often ineffective. The results of CL&P's unpreparedness and mismanagement were disastrous for the affected towns and their citizens. Docket No. 11-09-09, Werbner Pre-Filed Testimony, p. 3. Elected representatives from the towns of Simsbury, South Windsor, Tolland, Redding, Newtown, and Ridgefield appeared before the Authority and testified concerning CL&P's failures and the impacts on their towns. Decision in Docket No. 11-09-09, pp. 5-9. For example, CL&P could not tell Tolland leaders where Company crews were working, where the outages in town were, or provide real-time progress reports on restoration. Werbner PFT, p. 4. CL&P's inability to provide accurate restoration projections "had a material adverse impact on the town's ability to protect the health and safety of town residents." Glassman PFT, p. 5. Simsbury had no accurate information on which to schedule its shelter operations and care for its elderly and disabled. Id.

The Authority received more than one thousand written complaints and an additional one thousand telephone calls from customers concerning CL&P's deficient and inadequate response to the 2011 Storms. PURA stated that:

> [t]he majority of the customers who were affected by the 2011 Storms were concerned with the length of time it took the companies to restore service and the difficulty receiving information from the companies. Several customers stated that the companies were unprepared, mismanaged, and had underestimated the magnitude of the storm by not having sufficient repair crews available. Consumers believed that the lack of information provided by the companies left them unable to prepare for a longer than normal outage.
>
> Customer comment varied, but frustration regarding the amount of time the utility companies required to repair and restore service was a common theme. Several customers mentioned that Connecticut has the highest electric rates in the country and therefore, warrants better customer service. Customers suggested ways to help avoid future outages such as trimming trees and burying power lines. Others felt that customers with wells or septic systems should have their restoration of service prioritized because of the public health issues.
>
> Decision in Docket No. 11-09-09, p. 5.

CL&P's unreasonable level of preparedness and its failure to respond to the 2011 Storms in a reasonable manner caused the service restoration process to take longer than it otherwise would have. The failure of the municipal liaison program, as well as the delay in restoration for many customers, caused the towns to incur significant additional costs. Docket No. 11-09-09, Tr. 5/20/12, pp. 409-14. CL&P's management deficiencies with respect to the October Snowstorm, turned extended power outages into crisis situations, caused significant public anxiety and severely impacted residents' and towns' abilities to deal effectively with the outages.

Based on the foregoing, the Authority concludes that CL&P's performance in response to the 2011 Storms was deficient and inadequate and that the rates approved in this proceeding must encourage better storm response performance by CL&P

management. Therefore, the Authority will employ its authority under Conn. Gen. Stat. §16-19e(a)(3) and (5) to reduce the Company's ROE of 9.17% by 15 basis points for a period of one year to incent CL&P's management to show actual improvements in future storm responses. The ROE penalty of 15 basis points imposed on the Company for the Rate Year will reduce the revenue requirement by $4.394 million. Because the penalty will be in effect for the Rate Year only, the Authority will not require that Rate Year rates be designed to reflect the penalty. Instead, the adjustment will be made to the allowed revenue requirement target in the Company's first decoupling mechanism reconciliation. In following years, the Company may true-up to its full allowed revenue requirements. The Authority directs the Company to include the adjustment for the ROE penalty in its Rate Year decoupling mechanism reconciliation filing.

If CL&P fails to improve based on major storm preparedness and response and is found not to be in compliance with the outage restoration standards established by the Authority's November 1, 2014 Decision in Docket No. 12-06-09, PURA Establishment of Performance Standards for Electric and Gas Companies, the Authority may impose penalties as defined in that Decision and reduce CL&P's going forward ROE to create an incentive for CL&P to improve its performance.

The Authority recognizes that, subsequent to the 2011 Storms, CL&P has been required by statute and PURA decisions to implement certain proactive measures aimed toward improving CL&P's storm response performance. The Authority, as described below, has accounted for these improvements in determining an appropriate ROE reduction. The Authority also recognizes, however, that the real test of whether CL&P's storm performance will meet and exceed acceptable standards is by reviewing CL&P's actual future performance. Therefore, pursuant to its authority under Conn. Gen. Stat. §16-19e(a)(3) and (5), the Authority finds that it is just and reasonable in setting the structure and level of CL&P's rates to take into account evidence from recent past poor, deficient, imprudent and inefficient management performance with respect to storm response and create an incentive for CL&P to ensure that it attempts to improve its future management performance regarding future storm response. ROE adjustments such as the one implemented by the Authority in this Decision ensure that rates reflect prudent and efficient management. Conn. Gen. Stat. §16-19e(a)(5). Similar adjustments that have been upheld on appeal have been made by the Authority[35] and state public utility commissions in other jurisdictions.[36]

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[35] Conn. Natural Gas Corp. v. Conn. Dep't of Pub. Util. Control, 2010 Conn. Super. LEXIS 19, 17 (Conn. Natural Gas Corp. v. Conn. Dep't of Pub. Util. Control, CV094021664S, Superior Court of Connecticut, Judicial District of New Britain at New Britain, Memorandum of Decision dated January 6, 2010); Southern Conn. Gas Co. v. Conn. Dep't of Pub. Util. Control, 2010 Conn. Super. LEXIS 788, 19 (Southern Conn. Gas Co. v. Conn. Dep't of Pub. Util. Control, CV094021665S, Superior Court of Connecticut, Judicial District of New Britain at New Britain, Memorandum of Decision dated April 1, 2010).

[36] In re Citizens Utilities Company, 171 Vt. 447, 769 A.2d 19 (2000); US West Communications, Inc. v. Utilities & Transportation Commission, 134 Wn.2d 74, 949 P.2d 1337, 1358-1362 (1997); Mountain Fuel Supply Company v. Public Service Commission of Utah, 861 P.2d 414 (1993); Gulf Power Co. v. Wilson, 597 So. 2d 270, 270-274 (1992); Wisconsin Public Service Corp. v. Public Service Commission of Wisconsin, 156 Wis. 2d 611, 457 N.W.2d 502 (1990).

Specifically, the Authority finds that reducing the base ROE of 9.17% by 15 basis points to an ROE of 9.02% for the period 2015 is just and reasonable. For purposes of tracking ESM sharing and overearnings under Conn. Gen. Stat. §16-19(g), the Authority will base these calculations on an ROE of 9.02%. The primary purpose of the ROE reduction is to provide an incentive for CL&P to improve its storm response performance. If CL&P improves its future storm response performance, CL&P's ROE will not be subject to such reductions in the future.

If during the Rate Year, CL&P's storm response performance triggers the Authority to reopen this proceeding and find deficiencies in CL&P management's performance regarding storm response meriting extension of the ROE reduction, as determined by any proceedings opened to determine CL&P's compliance with the Docket No. 12-06-09 standards, the Company's ROE will remain at 9.02%.

In determining the allowed base ROE of 9.17% using the Authority's approved methodology, the Authority examined the testimonies, record evidence, various approaches and methodologies proffered by the Company and OCC witnesses, as well as the financial and economic factors in this proceeding. The Company had provided numerous ROE estimates that resulted in an expansive range from a low of 7.58% to an astronomical 12.51%. The OCC witness calculated a narrower ROE range of 7.80% to 9.0%. To test the results of the Company and OCC witnesses, the Authority conducted its own cost of equity analysis consistent with the methodologies exercised in past practice resulting in an allowed ROE of 9.17%. According to data from Regulatory Research Associates, the average of 101 reported electric utility rate case ROEs authorized by commissions in 2012, 2013 and so far in 2014, is 9.91%, with a reported range of 8.72% to 10.95%. Again, an ROE of 9.02% generated by the ROE penalty of 15 basis points, is supported within the general trend of interest rates and nationally authorized ROEs. The Authority notes that the reduced ROE of 9.02%, including the ROE penalty, falls within a range of ROEs determined by others to be reasonable for other utilities as well as the Company's and the OCC's limited range of ROE estimates. Setting the authorized return, inclusive of the reduction, should allow the Company to maintain its credit and financial integrity and will enable it to acquire sufficient new capital at reasonable terms to meet its service requirements.

The Authority finds that the 15 basis points ROE reduction is reasonable compared to previous reductions it has ordered in past proceedings. For example, in Docket No. 10-09-08, Application of United Water Connecticut, Inc. to Amend Rate Schedules, dated April 27, 2011, the Authority imposed a fifty basis points ROE reduction for imprudent management. In that case, the Authority found that the United Water Company's accounting, record keeping and billing methods were lacking and imposed the fifty basis point downward reduction to its ROE "as a penalty and strong warning to improve its business management practices." Id., 83.

Similarly, in the Decision dated June 30, 2009 in Docket No. 08-12-06, the Authority found that CNG did not properly include certain charges in its bills, found that the company's management that oversaw billing and rates was imprudent, and imposed a 10 basis point reduction to its return on equity as an imprudence penalty. The Authority noted in that case that such ROE adjustments are designed to ensure that rates reflect prudent and efficient management as required by Conn. Gen. Stat. §16-19e(a)(5).

In other cases, the Authority has repeatedly imposed substantial cost recovery disallowances where it has found CL&P acted imprudently. See Decision dated July 30, 1997 in Docket No. 96-10-06, DPUC Investigation Into Whether The Connecticut Light and Power Company Fulfilled its Public Service Responsibilities with Respect to its Nuclear Operations (imprudence disallowance of $600 million in replacement power costs due to shutdown of Millstone reactors / disallowance of additional $360 million in other incremental costs); Decision dated February 13, 1992 in Docket No. 90-02-03, Connecticut Yankee Nuclear Plant Shutdown (imprudence disallowance of $31,269,000 in replacement power costs for shutdown of Millstone reactor); Decision dated December 30, 1992 in Docket No. 91-10-02, DPUC Investigation into the Millstone 1 Shutdown on October 4, 1990 (imprudence disallowance of $2,865,000 in replacement power costs for shutdown of Millstone reactor).

The Authority finds that CL&P's mismanagement of its major storm response in 2011 merits a more severe ROE reduction than the 10 basis points reduction imposed on CNG and possibly the 50 basis points reduction imposed on United Water because more CL&P customers were negatively impacted and to a much greater degree by the extended outages following the 2011 Storms than customers were by the billing errors in the 2009 CNG matter or the accounting errors in the 2011 United Water matter. The OCC and AG each requested a 35 basis points reduction. The 15 basis points reduction falls within the range of these two past similar management-performance-based ROE reductions and is on the lower end of the 10 to 50 basis points range to reflect the steps CL&P has already taken since the 2011 Storms to be better prepared to respond to future storms.

The Authority may have assessed a greater reduction to CL&P’s ROE, if the Authority did not find that the Company has demonstrated a strong commitment to improving storm performance as demonstrated by its improvements in storm response protocols (such as pre-staging practices), emergency planning, and storm resiliency measures, all widely documented in this and a number of other PURA proceedings. Furthermore, improvements in emergency preparedness and response practices were confirmed in the Authority’s Decision dated August 21, 2013 in Docket No. 12-11-07. No parties or intervenors have argued that the CL&P storm response practices have not improved since the 2011 Storms.

While the Authority finds that the extent of CL&P’s improvements in storm resiliency measures weigh strongly against a larger ROE reduction, the Authority finds there remains a need to penalize CL&P and incentivize it to improve its future storm performance to avoid a repeat of the mismanaged and deficient performances that occurred in response to the 2011 Storms. The Authority notes that, but for the major improvement in CL&P’s storm preparedness and response subsequent to the 2011 Storms, the ROE reduction would have been substantially higher.

G. MERGER SAVINGS

In the Merger Decision, the Authority approved the merger agreement between Northeast Utilities and NSTAR, stating that it was in the public interest. Merger Decision, p. 48.

A condition of the merger settlement agreement provided that any future recovery of transaction costs is subject to Authority review and approval in a future rate proceeding. Merger Decision, Attachment A, Article 5.3. The instant docket is the first rate case since the merger was approved; therefore, the Authority will review the costs and merger savings associated with the merger.

The Authority found in the Merger Decision that total net benefits of approximately $783.8 million were expected on an overall, enterprise-wide basis with an estimated 38.5 percent of that amount, or approximately $301.8 million, allocable to CL&P's transmission and distribution operations based on 2011 financial data. The companies provided the analysis of savings through a Merger Integration Report (MIR). The Net Benefits Analysis was developed by analyzing the current cost structures of NU and NSTAR, with total actual labor costs disaggregated into nine principal functional areas for analysis. The savings quantified in the Net Benefits Analysis were estimated on the basis of potential reductions in labor and non-labor costs within corporate and administrative functional areas. For non-labor cost savings, the companies examined actual costs in 17 potential areas of savings, including 13 categories of corporate and administrative costs (e.g., insurance, facilities, benefits and fleet costs) and 3 categories of purchasing costs (procurement, inventory and contract services). The same methodology was used to quantify merger-related savings in this case. Mahoney PFT, pp. 6 and 7. The Company submitted an updated MIR summarizing the areas of savings, updated through June 1, 2014. Mahoney PFT, Exhibit MJM-2A. The updated MIR forecasts an increase, from the amount presented in Docket No. 12-01-07, in merger savings on an enterprise-wide basis of $92.8 million for a total of $876.6 million. Id., p. 4.

The Company stated that over the 10-year post-merger period, that the MIR covers, the generated savings will far outweigh the costs incurred to complete the merger. The merger integration report indicates total estimated merger-related costs of $119.4 million. Mahoney PFT, Exhibit MJM-2A, p. 4. The Company proposes to share costs associated with the merger based on the same percentage that savings are allocated. The Company proposes to amortize this amount over 10 years, without a return. The CL&P portion of the $119.4 million is calculated at $25.204 million in total or $2.520 million annually for ten years. Application, WP C-3.34, p. 3. In justification, the Company stated that the projected cumulative net merger-related savings of $876.6 million are significantly higher than the costs incurred to complete the merger. PFT Mahoney, pp. 7 and 8.

Article 5.3 of the settlement agreement in the Merger Decision states the following:

> Merger related payments made to officers leaving the employ of NSTAR, NU, any of the temporary or surviving entities engaged in the proposed merger transactions, the operating companies, or their successors (together, the "post-merger organization") in the

> category of "change of control" payments, or to executives remaining with the post-merger organization in the category of "retention payments," shall be recorded at the parent company level upon the merger close and shall not be eligible for recovery as a merger related cost or otherwise from customers.

The Authority reviewed the expense items that the Company is claiming as merger-related costs and finds that CL&P has appropriately removed the above stated payments from costs associated with the merger in accordance with the settlement agreement. The Company has also verified exclusion of these payments through responses to interrogatories and testimony, including the response to Interrogatory AC-45.

With regard to the remaining expense items that compose the $119.4 million, the Authority has reviewed these items and notes that they include amounts for: legal fees, bankers' fees and non-executive separation costs. Response to Interrogatory AC-114. These items are customary and can be expected to be incurred in this type of transaction. The Authority therefore approves of the items to be included for cost recovery.

No party addressed this issue in its brief or reply brief.

The Authority agrees that the merger has provided benefits to customers which exceed the costs to achieve those reductions. The Authority therefore approves the Company's request to amortize the CL&P portion of merger costs of $2.520 million annually for 10 years.

In terms of going forward merger costs and savings that the Authority can expect to see in future CL&P filings, the Company stated:

> I guess what we would see moving away from this rate case is our ability to retain those merger savings that we have already achieved at this point. I believe after this rate case, while we'll have merger savings by holding onto the savings that we've achieved over time, I wouldn't go as far as to say that the attrition going forward through 2017 will be related to the merger. At some point, and I believe at this point with the rate case, we will start to look at things as business as usual and that just acquiring more efficiencies. To the extent, as Mr. Chung explained earlier, that these efficiencies would have occurred only but for the merger, then we will recognize them as merger related.

Tr. 9/5/2014, pp. 1445 and 1446

At the conclusion of this rate case and going forward, the Company should move from identifying items that could be considered merger related towards a business as usual approach. In the Company's next filing, the Authority expects to see little to no claim for merger-related initiatives or cost recovery. Future efficiencies should be attributed to management initiatives under a business structure that will have been in place for over five years at the time of the Company's next rate filing in 2017.

H. DECOUPLING

The Authority approves the same decoupling mechanism for CL&P as it approved for UI. This decoupling mechanism provides for customers to pay the Company for any under-collection of revenues and that CL&P credit back any over-collection of revenues. CL&P may not retain any revenues. See, Decision dated February 4, 2009 in Docket No. 08-07-04, Application of The United Illuminating Company to Increase its Rates and Charges, pp. 126 and 127; Decision dated September 1, 2010 in Docket No. 08-07-04RE02, Application of The United Illuminating Company to Increase its Rates and Charges - Review of Decoupling Pilot, Pension Tracker, ROE Sharing Mechanism, and GET Adjustment, p. 9; Decision dated August 14, 2013 in Docket No. 13-01-19, pp. 126, 146 and 147. In reaching this determination, the Authority reviewed the language of the decoupling statute, the Company's proposal, the positions of the parties and past Authority Decisions addressing decoupling. The Authority finds that the decoupling rate will be a single, company-wide rate per kWh. The Authority also finds that the Company's proposal to include all sources of revenue in the decoupling calculation is appropriate. The Authority does not approve CL&P's proposal to assign carrying charges to either an over- or under-recovery or to any deferral. The Authority further directs that the present CIAC practices remain the same without any of CL&P's alterations. Additionally, as detailed in Section II.F.4 above, the 15 basis points reduction to the Company's for the Rate Year will reduce the revenue requirement and be reflected in an adjustment to the allowed revenue requirement target in the Company's first decoupling mechanism reconciliation. In following years, the Company may true-up to its full allowed revenue requirements. The Authority directs the Company to include the adjustment for the ROE penalty in its Rate Year decoupling mechanism reconciliation filing.

The OCC, AG and BETP expressed in their Written Exceptions their concern with including the adjustment for the ROE penalty in the decoupling reconciliation, and recommended that Rate Year rates be reduced immediately to reflect the penalty. OCC Written Exceptions, pp. 15-17, AG Written Exceptions, p. 4-6, BETP Written Exceptions, p. 2. They indicated this rate treatment means that customers may not see the full benefit of this reduction for two and a half years or more. This was not the Authority's intent. As discussed in the June 27, 2014 letter issued by the Authority and the Prehearing Conference held on June 19, 2014, it was agreed upon by the parties that the effective date of new rates will occur after the effective date of the Rate Year, which begins December 1, 2014. Similar to its directive for the ROE penalty, the Authority is not requiring the Company to design rates that reflect the delayed implementation of rates. Therefore, the Authority anticipates a shortfall in Rate Year revenue due to the delayed implementation of rates. In other words, customers are realizing the benefit of the penalty immediately by a delay in the implementation of rates rather than over the course of the Rate Year.

The decoupling statute, Conn. Gen. Stat. §16-19tt, provides in relevant part:

> (b) In any rate case initiated on or after July 8, 2013, or in a pending rate case for which a final decision has not been issued prior to July 8, 2013, the Public Utilities Regulatory Authority shall order the state's gas and electric distribution companies to decouple distribution revenues from the volume of natural gas and electricity sales. For electric distribution companies, the decoupling mechanism shall be the adjustment of actual distribution revenues to allowed distribution revenues . . . . In making its determination on this matter, the authority shall consider the impact of decoupling on the gas or electric distribution company's return on equity and make any necessary adjustments thereto.

With respect to the electric decoupling, the legislature expressed its intent to specifically require one type of mechanism with language clearly stating that the "decoupling mechanism shall be the adjustment of actual distribution revenues to allowed distribution revenues."

In the Application, the Company originally proposed a decoupling methodology that would reconcile actual revenues to PURA-approved revenues. At the end of each Rate Year, the Company would calculate the annual difference in revenues and establish a single kWh rate applicable to all customers over the following year. In addition, carrying charges[37] and a prior-year decoupling true-up will apply. The Company proposed to retain the revenue collected from post-rate year customers requiring a service set[38] (new service customers). The Company claimed that this money is needed to compensate them for the cost of installing new equipment. Absent retention of new service customer revenues, the Company suggested that new service customers be charged a 100% CIAC grossed up for income taxes. The annual process will continue until the Company's next rate application where PURA-approved revenues will be reset. Goodwin PFT, pp. 9-11.

During the hearing, the Company revised its decoupling proposal. Under the revised proposal the Company would add revenues received from post-rate year new service customers to the allowed revenues established in the instant case. The original proposal subtracted new service customer revenues from actual revenues. The decoupling amount is identical in either case. According to the Company, the new approach satisfies the language of the statute[39] because the Authority has great latitude in determining allowed revenues. Further, the Company argued that:

> In addition, there are other statutory provisions that relate to CL&P's statutory right to recover revenues lost due to various Connecticut policy initiatives regarding renewable energy and collectively ensure that the

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[37] The carrying charge as proposed will equal the Company's overall cost of capital.

[38] Service set customers are new customers lacking any electrical service at their location. The Company will need to install a meter, service and possibly extend the distribution system as well to service these customers.

[39] Conn. Gen. Stat. §16-19tt(b) defines decoupling for electric companies as follows: "For electric distribution companies, the decoupling mechanism shall be the adjustment of actual distribution revenues to allowed distribution revenues."

> Company can recover the revenues due to it as a result of PURA rate rulings (provided below). Collectively, these provisions establish that the Company has a right to recover revenues that are lost due to initiatives such as energy efficiency and the waiver of back-up charges for DG[40] customers, which is recovery obtained through the NBFMCC[41] rate. Other programs resulting in lost revenue (going forward after rates are set in this case), such as virtual net metering will be recovered in future NBFMCC rate filings.
>
> Late Filed Exhibit No. 15.

The Company reiterated the PURA's right to establish allowed revenues in its preliminary brief and also argued that the decoupling statute must be read in concert with the Authority's responsibility to establish just and reasonable rates.

> In regard to §16-19tt, the legislative directive to implement a revenue decoupling mechanism for CL&P cannot be read in isolation, but rather it must be read within the context of, and consistent with, PURA's full rate-making authority as set forth in §§16-19, 16-19e(a) and related sections. PURA cannot implement decoupling in a manner that would cause CL&P's rates to be less than just and reasonable, or insufficient to cover its operating costs. Conn. Gen. Stat. §16-19e(a)(4). Therefore, the Authority has broad discretion to establish "allowed revenue" for purposes of the decoupling tariff to equal the revenues associated with the revenue requirement approved in this case for the rate year, plus the distribution revenues collected from new customer connections after the rate year. Absent the inclusion of the new customer revenue as part of allowed revenue, the decoupling mechanism would result in the Company incurring incremental capital investment and cost of service associated with the new customers, with no means of recovering or offsetting these costs short of filing a new rate case.
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> CL&P Preliminary Brief, pp. 7 and 8.

Other parties to the docket presented their positions regarding CL&P's decoupling proposal. The CIEC wants all large C&I and DG customers to be exempt from the proposed company-wide decoupling rate. Absent full exemption, the CIEC recommended a decoupling rate that is equally applicable to all rate classes on a company-wide rate per kWh basis. CIEC Brief, pp. 22-24. The AG requests that the Authority reject the Company's proposed decoupling methodology because it lacks the fundamental symmetry contemplated by the decoupling statute and the Company's proposal to retain revenues from new service customers is not permitted by decoupling statute. AG Brief, pp. 21, 22 and 23.

The Bureau of Energy and Technology Policy (BETP) supported the Company's proposal. The Company should be allowed to retain new service customer revenues because it is only a minor adjustment that may help delay the need for a new rate case.

[40] Distributed generation (DG).

[41] Non-bypassable Federally Mandated Congestion Charge

BETP also considered decoupling to be an effective cost-recovery alternative to increasing fixed charges as proposed by the Company. BETP Brief p. 13; Reply Brief, p. 1.

Environment Northeast (ENE) favors granting the Company full revenue decoupling because it will not hamper state energy policy and can be used to replace the need for fixed charges. ENE defines decoupling as actual revenue coming in less than allowed revenues. ENE Brief, p. 8.

Wal-Mart[42] argued that since demand-metered customers are already paying substantially excessive rates, no decoupling charge should apply. Additionally, a company-wide kWh decoupling charge as proposed by the Company only introduces further inter-class subsidization. For rate classes that have no volumetric kWh rates, a kWh decoupling charge also shifts cost responsibility from lower load factor customers to higher load factor customers. Wal-Mart Brief, pp. 4-6.

The OCC disagreed with the Company's position in three respects. First, it recommended that decoupling be applied at either the individual rate class level or at a broader residential, commercial and industrial level. Use of broader levels would prevent potentially severe impacts in customer classes with relatively few customers. Second, whereas the Company proposed to include carrying charges equal to its weighted average cost of capital, the OCC argued that CL&P's short-term cost of debt is more appropriate. Finally, the Company's proposal to adjust either allowed or billed revenues to remove revenues from new service customers is outside the scope of the legislation and should be denied by the Authority. OCC Brief, pp. 138-142. In response to the CIEC's argument that larger rate classes should be exempt from decoupling because they are already decoupled through rate design, the OCC stated that a reduction in their demand levels, for example, would be trued-up by other rate classes. Further, the OCC disagreed with the BETP's claim that the Company should be allowed to retain new service customer revenues. The OCC pointed out that retained revenues include all customer, energy and demand charges that exceed the cost of newly installed facilities. OCC Reply Brief, pp. 22-25.

The Authority finds that CL&P's proposed decoupling mechanism is not permissible, based on the plain and express language of the decoupling statute. The decoupling statute requires the adjustment or reconciliation be made on the basis of a true up between allowed distribution revenues and "actual distribution revenues." The statute makes no provision for the exclusion of any revenue, such as new customer revenue, from the revenue reconciliation. The Authority, therefore, declines to interpret that statute, as CL&P urges, to conclude that certain actual new customer revenues should be excluded from the decoupling true up adjustment or treated as an upward adjustment to allowed distribution revenue.

Besides not being permitted by the plain and express statutory language, the Authority also finds that CL&P's proposal is contrary to the legislative intent of the decoupling statute to establish a balance and symmetry between the electric or gas

[42] Wal-Mart Stores East, LP and Sam's East are intervenors collectively referred to as Wal-Mart.

distribution companies and their customers.[43] In its Decision dated January 22, 2014 in Docket No. 13-06-08, the Authority described the legislative intent for:

> . . . decoupling to be a simple true-up mechanism established to decouple revenue from fluctuations in sales. If utility rates reflected only fixed monthly charges, then fluctuations in revenue would parallel customer count. As expressed to the PURA by Connecticut utilities many times in numerous dockets, decoupling only permits the utility to recover its revenue requirement calculated by the Authority as the amount just adequate to provide safe, reliable service, no more, no less. Decoupling is symmetrical in theory in that it requires ratepayers to contribute missing revenues to utilities and in turn, for utilities to refund additional revenues to ratepayers. In practice, however, decoupling can favor ratepayers or utilities over extended periods. For example, in a warming world of expanding customer conservation coupled with poor economic activity, utilities will collect more from ratepayers than they refund. Alternatively, in a situation of unprecedented customer growth, ratepayers would be expected to share in the financial benefits.

Docket No. 13-06-18 Decision, p. 122.

The Company's legal argument submitted in support of its latest proposal to adjust allowed revenues, centers on the Authority's need to read the decoupling statute in concert with its responsibility to approve nothing less than just and reasonable rates. The Authority is aware of those requirements. Decoupling is not a rate developed to recover underlying, prudently incurred costs. It is a true-up mechanism for revenues previously designed fully in accordance with the Authority's just and reasonableness responsibility. Adding future unknown costs to today's allowed revenues to incorporate a single item of cost, even if it is described by some as minor, it is another version of single-issue rate-making that violates the symmetrical balance of decoupling. Therefore, the Authority rejects the Company's decoupling proposal. The Company will be directed to revise its proposed Decoupling Rates Rider to reflect the formula approved for UI. That formula is consistent with the enabling legislation and was implemented for all other utilities granted decoupling to date. If at any time in the future, CL&P determines that decoupling and other approved rate mechanisms are insufficient for the Company to collect enough revenue to provide adequate and reliable electric service at just and reasonable rates, recover its costs, and give CL&P a reasonable opportunity to earn a reasonable return, the Company may file a rate case application seeking an increase to its allowed distribution revenues and other rate relief.

The Authority has determined that present CIAC practices will not to be altered. While it is true that new service customer revenues will be returned to ratepayers, a new customer has no control over the situation and should not provide the Company with a contribution newly calculated outside of existing practices. Since new service

[43] In this proceeding, the Company's witness also acknowledged that the decoupling relationship is intended to be symmetrical, with risks and potential benefits for both the Company's shareholders and its ratepayers as stated below. Tr. 9/3/14, pp. 955 and 956.

subscribers tend to be customers for many years, valuing their contribution to costs must be normalized over the life of the analysis. Imputing zero revenues for a few years of a 50-year revenue contribution stream is inappropriate. The potential loss of revenue from new service customers is more than balanced from the protection ratepayers stand ready to provide should sales decrease for any reason.

The Authority finds that the decoupling rate will be a single, company-wide rate per kWh. Customers serviced by rate classes lacking volumetric distribution rates should be charged the same rate based on their monthly kWh usage. The Authority understands the OCC's concern that a single, company-wide decoupling rate inevitably involves inter-class subsidizations that are always inappropriate when viewed from the perspective of any single class. Nonetheless, decoupling is only a true-up mechanism that involves minimal dollars in comparison to total distribution revenues. Individual customers are involved in this true-up; but only to the extent of their relative level of annual consumption. Small consumption customers are charged or benefitted less than large consumption customers. Decoupling at either the rate class or broader group level introduces the possibility of simultaneous debit and credit charges within the same true-up year. Ultimately, decoupling is a blunt regulatory or administrative tool utilized until the rate formula can be rebalanced in a future rate case. Decoupling will supersede the existing conservation adjustment mechanism (CAM) and lost revenue true-ups within the FMCC reconciliation process. The Company will be directed to propose a phase-out formula at its next scheduled CAM and Federally Mandated Congestion Charge reconciliation filings.

The Authority finds that the Company's proposal to include all sources of revenue in the decoupling calculation is appropriate. A regulatory asset (debit or credit) will be created following Authority approval of the Company's annual decoupling calculation. The asset will be written off monthly using actual billings. The last month's write-off will use actual billed revenues and estimated net unbilled revenues for the year. Since allowed revenues will not change during the year, all accounting and financial reporting documents prepared for public consumption will reflect a forecast of normalized allowed revenues for the period in question. Customer bills will present the decoupling charge on a separate line item entitled Revenue Adjustment Mechanism per kWh. Annual requests to the Authority for approval of a new decoupling rate may follow the format recently employed by UI. Annual decoupling filings should be made expeditiously following the availability of complete data. The actual rate calculation will use forecasted sales for the upcoming collection year. The decoupling rate will not be grossed-up for gross receipt tax or uncollectible expense. Periodic decoupling audits will be conducted by the Authority.

I. EARNINGS SHARING MECHANISM

An earnings sharing mechanism (ESM) is a ratemaking mechanism that shares a company's earnings in excess of its allowed ROE. The purpose of an ESM is to provide for the equitable distribution of a company's earnings above its allowed ROE between the company's customers and shareholders. Typically, the Authority has established the sharing threshold at the Company's allowed ROE with the sharing distributed equally with 50% to shareholders and 50% for the customers. Since 1999, the

Company has operated under an ESM whereby earnings in excess of the allowed ROE are shared with ratepayers.

Connecticut's over-earnings statute, Conn. Gen. Stat. §16-19(g), allows the Authority to review a company's earnings if an earned ROE exceeds a company's authorized ROE by 1% point for a period of six consecutive months, equivalently two fiscal quarters. The Authority has a long tradition of using an ESM and has approved these for companies as an incentive to shareholders. Its implementation allows shareholders to capture a portion of potential overearnings and also avoiding an overearnings financial review that would be otherwise initiated by the Authority. The ESMs have been implemented in the past for electric, gas and water utilities.

In this proceeding, CL&P is proposing a change to the existing ESM by suggesting a 100-basis point deadband above its authorized ROE, within which, there would be no sharing. Between 100 and 150 basis points above the allowed ROE, earnings would be shifted with 75% shareholders and 25% shared to ratepayers. For earnings above 150 basis points, CL&P offers to share earnings equally. According to the Company, the proposed ESM may help mitigate CL&P's exposure to the downside risk of earnings deficiencies. CL&P claims that if it could retain a higher margin of earnings, it would provide a strong incentive for the Company to undertake broad-scale efficiency measures that would consume management focus, institutional resources and, in some cases, costs to achieve, but would reduce the cost of service for customers in the next rate case. Hevert PFT, pp. 42–47.

A recommendation to reject CL&P's proposed changes to the ESM was also provided by Wal-Mart. Per traditional regulatory practice, the Company has the opportunity, but not the guarantee to earn its authorized return. Chriss PFT, p. 14. According to Mr. Chriss, over-earnings indicate that rates are set too high and should be reduced. Implementation of the proposed deadband above the allowed ROE results in the potential for the Company to significantly over-earn with no offset to customers of the rates that have been set too high. Chriss PFT, p. 15. Mr. Chriss stated that the current ESM already provides an incentive for the Company to maximize the efficiency of its operations, as achieved cost reductions that increase earnings over the authorized return are awarded with 50% of the over-earnings going to the Company. Id. Mr. Chriss also claims that the Company has not provided sufficient justification to deviate from the precedent established by PURA with respect to ESMs. Wal-Mart Brief, p. 8.

Additionally, the CIEC stated that the Company's proposal would significantly reduce the ability of ratepayers to share in over-earnings without providing any additional corresponding benefit. CIEC Brief, p. 29. The CIEC concurs with Mr. Chriss that CL&P is not entitled to nor guaranteed to over-earn its rate of return. Id. Contrary to the Company's assertions, the record in this proceeding demonstrates that the current ESM already provides sufficient incentive to maximize the efficiency of its operations. CIEC Brief, p. 30. The AG also recommends that CL&P's proposed ESM be rejected as unfair to ratepayers. AG Brief, p. 11. Since the Company can expect to see increasing earnings and savings resulting from efficiencies created by the merger between NU and NSTAR, the AG claimed that CL&P's proposed ESM would funnel the vast bulk of those savings back to its shareholders. Id.

The Authority finds that CL&P's current ESM provides sufficient incentive to maximize the efficiency of its operations as the Company is rewarded for its efforts with 50% of any earnings above its authorized ROE. Under the existing ESM, the Company has achieved efficiencies associated with the merger with savings in operating expenses and by optimization of its facilities. The Authority expects the Company to continue to strive for efficiencies in its operations. The current ESM is also consistent with other recent ESMs that were approved by the Authority for electric, gas and water utilities. The Company should maintain an equal share of the benefits and savings and continue to pursue efficiency in all areas of its operations. The Authority directs CL&P to continue its existing ESM. The earnings sharing mechanism shall remain in effect until the Company's next rate case where it will again be reviewed. Accordingly, the Company's excess earnings over its allowed ROE of 9.02%, or 9.17% in 2016 and beyond, calculated using the cost of capital method will be shared 50/50 ratepayers/Company. The ratepayers' share of any such excess earnings will be returned through a line item credit on their bills.

J. Rates, Revenue and Tariffs

1. Sales Forecast

CL&P stated that historically, electric rates have generally followed the economy, and the relationship is critical to understanding and forecasting electric use. The level of economic activity is a driver in determining customers' purchase and operation of electric equipment and appliances that subsequently determine electric demand. Residential customers are determined by the number of households, and residential electric sales are correlated with household income. Commercial sales are driven by growth in the non-manufacturing sector, which also provides jobs that produce additional residential sales growth. Industrial sales are driven by manufacturing employment and productivity. For this reason, a sales forecast is generally a reflection of the underlying economic forecast. The economic forecast used by CL&P in this case was developed by Moody's Economy.com in July 2013. Plecs PFT, pp. 1 and 2.

While the recession had a dramatic impact on sales, CL&P indicated a recovery seems to be underway and its economic forecast predicts that this modest recovery is expected to continue throughout the forecast period. In 2011 and 2012, total retail sales declined by 0.5% and 0.2%, respectively, on a weather-normalized basis. However, 2013 proved to be a turning point, with sales up 0.7% over 2012. Residential sales growth has been flat to positive, accelerating during the most recent years of the economic recovery. Commercial sales only recently turned positive in 2013, and industrial sales growth has been volatile, growing in 2012 before a sharp decline in 2013. While the economic recovery has been volatile for several years, it now appears to be gaining some momentum in some sectors, with some degree of stability in non-manufacturing employment and household incomes. The Company nevertheless expects that the industrial sector will continue to be volatile and difficult to predict. Id.

CL&P forecasts retail sales to remain relatively flat through 2016. Forecasted CL&P retail sales are shown in the chart below:

Table 66

Exhibit CAP-7											
CONNECTICUT LIGHT AND POWER COMPANY- TOTAL FRANCHISE SALES											
CALENDAR ELECTRIC SALES											
GIGAWATT HOURS											
									RAIL-		TOTAL
	RES.		COM.		IND.		ST. LIGHT.		ROAD		RETAIL
	SALES	% CH	SALES	% CH	SALES	% CH	SALES	% CH	SALES	% CH	SALES
FORECAST											
2014	10,295	1.1%	9,525	0.9%	2,290	-1.0%	96	-1.3%	194	2.3%	22,401
2015	10,307	0.1%	9,514	-0.1%	2,285	-0.2%	95	-1.0%	196	0.9%	22,397
2016	10,387	0.8%	9,528	0.2%	2,267	-0.8%	94	-1.0%	198	0.9%	22,474

Application, Exhibit CAP-7.

The resulting flat sales forecast reflects both an anticipated modest improvement in economic conditions in certain sectors, and it includes the effect of expanded Company-sponsored energy efficiency programs, which are expected to add approximately 300 gigawatt hours (GWh), or nearly 1.5% of annual sales, of new energy efficiency measures per year. The forecast is structured to consider previously installed measures, which still provide an energy savings benefit, and the estimated impacts of future programs, without double-counting those savings with the savings implied by the regression model's historical relationships.

Historically, the Company's sales have very closely mirrored economic activity. In the last 10 years, that relationship held subject to adjustments for energy price spikes and DG activity. The Company stated it expects that this sales-economy relationship to hold through the forecast period, subject to additional adjustments for growth in DG and energy efficiency programs. However, CL&P cautioned that a number of factors may affect the sales outlook such as weather, economic activity, energy prices, energy efficiency, and DG activity. Plec PFT, pp. 3-8.

a. Forecasting Methodology

i. Trend Forecast

CL&P traditionally used statistically adjusted end-use models to forecast sales by customer class, which were useful in identifying the end-use factors that are driving energy use. For the purposes of the instant case, CL&P changed its sales forecasting methodology to a traditional econometric, or trend, model to forecast customer and sales for the Rate Year. The Company found that both approaches produce similarly reliable results. It decided to use the econometric modeling approach because it produces reliable results with less complexity at lower cost. CL&P Response to Interrogatory OCC-204. The Company forecasted sales on the customer class level, (e.g., Residential, Commercial, Industrial, Street Lighting and Railroad). Late Filed Exhibit No. 16, Attachment 1; Tr. 9/3/14, pp. 825-827. The Company indicated it performed a weather normalization study in developing the rate year sales forecast and associated revenues. CL&P Response to Interrogatory OCC-123.

The Company also provided its lost sales associated with the major recent weather events. CL&P lost approximately 159 GWh in 2011, or 2.2% of its sales for the affected period, due to Hurricane Irene and the October 2011 snowstorm. In 2012, CL&P lost approximately 86 GWh, or 2.6% of its sales for the affected period, due to Hurricane Sandy. Late Filed Exhibit No. 16, Attachment 2. The Company adjusted the forecast models' dataset historical for the impact of these storms by using a separate set of weather-specific sales models to capture the sales impacts of both statistically significant weather events and the typical variations caused by heating and cooling degree days. In some cases where a storm is substantial, it used a binary variable to account for some unusual relationships between the economic driver and the actual sales experience to make sure that that relationship was not something that the model would interpret as a normal response. Late Filed Exhibit No. 16; Tr. 9/3/14, pp. 828 and 829.

ii. Out of Model Adjustments

The Company made a series of “out of model” adjustments to the trend forecast to adjust sales where new demand side programs are in place and/or it finds the trend forecast is not accurately capturing a particular sales trend. For instance, the Company increased its C&LM spending, and expects to lose additional sales that are not reflected in historical sales trend which only include the base conservation savings. Other items that the Company adjusted for are distributed generation, the residential solar program, electric vehicle program, the low- and zero-emission renewable energy credit (LREC/ZREC) program and large customer changes. The Company provided a summary of the out of model adjustment:

Table 67

CL&P Out of Model Adjustments GWH									
	Residential Adjustments								
Year	Eviews Trend Forecast	Energy Efficiency	LREC/ZREC Program	Leap Year	Residential Solar Program	Electric Vehicles	**Total Out of Model Adjustments**	Final Forecast	
2014	10,306	-10	-5	0	-10	14	**-11**	10,295	
2015	10,355	-36	-12	0	-20	21	**-47**	10,307	
2016	10,446	-61	-19	21	-30	30	**-59**	10,387	
	Commercial Adjustments								
Year	Eviews Trend Forecast	Energy Efficiency	LREC/ZREC Program	Leap Year	2008 DG Program	Large Customer Changes	**Total Out of Model Adjustments**	Final Forecast	
2014	9,863	-7	-70	0	-280	19	**-338**	9,525	
2015	9,921	-25	-168	0	-284	69	**-407**	9,514	
2016	9,998	-43	-268	24	-285	102	**-470**	9,528	
	Industrial Adjustments								
Year	Eviews Trend Forecast	Energy Efficiency	LREC/ZREC Program	Leap Year	2008 DG Program	Large Customer Changes	Large Customer Self-Generation Unit	**Total Out of Model Adjustments**	Final Forecast
2014	2,778	-2	-19	0	-385	19	-102	**-488**	2,290
2015	2,785	-7	-46	0	-385	39	-102	**-500**	2,285
2016	2,794	-11	-73	6	-385	39	-102	**-527**	2,267

Late Filed Exhibit No. 8.

iii. Rate Class Sales Allocation

Once the sales forecast was developed at the customer class level, the Company looked at the test year billing data from its records, specifically the relationships based on the customer class versus rate class sales levels. In developing the rate class level forecasts, CL&P then used those relationships to extrapolate the customer, demand, and sales billing determinants. CL&P utilized the relationships of customer class to rate class sales in the test year to develop the rate year comparable billing units by rate class. Tr. 9/3/14, p. 832.

b. Sales Forecast Results

The table below summarizes CL&P's proposed Rate Year rate revenue at present rates and the forecasted changes in customer, sales and revenues from the Test Year, allocated among each of the rate classes:

Table 68

		Test Year revenues at current rates				Rate Year revenues at current rates				% Change		
Rate	Schedule/Description	Average Number Of Customer Bills Rendered	Weather Normalized Sales (mWh)	Average Current Rates (cents/kWh)	Base Revenue ($000)	Average Number Of Customer Bills Rendered	2015 Forecasted Sales (mWh)	Average Current Rates (cents/kWh)	Base Revenue ($000)	Customers	Sales	Revenue
1	Residential - Regular	969,421	8,331,016	18.40	$ 1,532,836	984,231	8,461,362	18.40	$ 1,556,750	1.53%	1.56%	1.56%
5	Residential - Electric Heat	138,749	1,828,279	17.61	$ 321,999	138,749	1,828,279	17.61	$ 321,999	0.00%	0.00%	0.00%
7	Residential - Time-Of-Day	486	6,066	17.40	$ 1,055	493	6,156	17.40	$ 1,071	1.53%	1.48%	1.48%
18	Controlled Water Heating *	196	878	16.74	$ 147	196	878	16.74	$ 147	0.00%	0.00%	0.00%
27	Time-Of-Day (TOD) General	74	13,934	18.85	$ 2,626	74	13,961	18.85	$ 2,632	0.81%	0.20%	0.20%
29	Outdoor Lighting	205	3,211	23.96	$ 769	208	3,232	23.99	$ 775	1.58%	0.64%	0.79%
30	Small General	97,793	3,257,931	18.20	$ 593,030	99,250	3,275,128	18.22	$ 596,593	1.49%	0.53%	0.60%
35	Intermediate General	3,053	1,142,788	15.64	$ 178,739	3,095	1,148,500	15.65	$ 179,744	1.37%	0.50%	0.56%
37	Intermediate TOD	1,514	1,282,415	15.24	$ 195,426	1,528	1,285,729	15.24	$ 195,975	0.96%	0.26%	0.28%
39	Interruptible Menu	8	235,489	9.78	$ 23,020	8	235,489	9.78	$ 23,020	0.00%	0.00%	0.00%
40	Church and School	2,116	115,402	17.51	$ 20,212	2,116	115,402	17.51	$ 20,212	0.00%	0.00%	0.00%
41	Large Church and School	16	15,096	17.09	$ 2,579	16	15,096	17.09	$ 2,579	0.00%	0.00%	0.00%
55	Intermediate TOD Manufacturers	320	681,030	12.56	$ 85,569	317	674,097	12.56	$ 84,700	-0.86%	-1.02%	-1.02%
56	Intermediate TOD Non-Manufact	955	2,021,971	12.99	$ 262,678	968	2,032,033	12.99	$ 264,026	1.35%	0.50%	0.51%
57	Large TOD Manufacturers	139	1,095,288	11.68	$ 127,927	136	1,077,844	11.68	$ 125,898	-1.58%	-1.59%	-1.59%
58	Large TOD Non-Manufacturers	205	2,036,690	12.20	$ 248,407	208	2,052,918	12.20	$ 250,402	1.21%	0.80%	0.80%
115	Unmetered	2,633	53,500	16.49	$ 8,820	2,652	53,500	16.49	$ 8,820	0.71%	0.00%	0.00%
116	Street & Security Lighting	2,349	92,563	26.41	$ 24,445	2,349	92,563	26.41	$ 24,445	0.00%	0.00%	0.00%
117	Partial Street Lighting Service	333	23,425	14.43	$ 3,380	333	23,425	14.43	$ 3,380	0.00%	0.00%	0.00%
119	Special Contracts	3	1,320	37.31	$ 492	3	1,320	37.31	$ 492	0.00%	0.00%	0.00%
	Total	1,220,369	22,238,292	16.34	$ 3,634,158	1,236,734	22,396,911	16.36	$ 3,663,662	1.34%	0.71%	0.81%

Exhibit EAD-14, pp. 1 and 2.

c. Position of the Parties

None of the Parties commented on CL&P's proposed sales forecasting methodology or the forecast results in their respective testimony or Briefs.

d. Authority Analysis

The Company is forecasting customer growth of approximately 1.2% for the residential, 1.4% for the commercial and 0.4% for the street lighting customer classes over test year levels, and a decrease in customer growth in the industrial class of 1.2%. CL&P Responses to Interrogatories OCC-304 and OCC-305. The Authority reviewed CL&P's forecasting methodology and forecasting results and finds the methodology reasonable and the results acceptable for setting rates. The sales numbers for 2015 reflect a modest level of growth in sales, consistent with observed and forecasted economic trends, known customer changes, and offset by expected sales reductions due to various demand-side program initiatives. The customer forecast is also reasonable given historic trends and expected changes, as discussed in the case.

2. Operating Revenue

CL&P filed the following summary of earned operating revenues for the Test Year, forecasted Revenue at present rates using the sales forecast discussed in Section II.J.1, Sales Forecast, proposed Rate Year revenues based on the rate request, and the associated revenue increase.

Table 69

DISTRIBUTION COSTS											
OPERATING INCOME SUMMARY - RATE YEAR ENDING 2015											
Description	Rate Year Ending 2015 at Current Rates		Required Increase			GET & Uncollectible Adjustment		Required Increase including GET & Uncollectible		Rate Year Ending 2015 at Proposed Rates	
Operating revenues (distibution only)	$	905,882	$	108,101	(a)	$	8,607	$	116,708	$	1,022,590
Operating revenues (storm cost)	$	-	$	82,928	(a)	$	6,603	$	89,531	$	89,531
Operating revenues	$	-	$	23,474	(a)	$	1,869	$	25,343	$	25,343
		905,882	$	214,503		$	17,079	$	231,582	$	1,137,464

Application, Schedule C-1.0.

CL&P's proposed Rate Year revenue at present rates of $905.882 million consists of $883.661 million of rate revenue based on applying CL&P's current distribution rates to forecasted sales volumes and $22.221 million in "other" revenues. Application, Schedule C-3.1.

a. Rate Revenue at Present Rates

Based on the sales forecast discussed in Section II.J.1, Sales Forecast, CL&P calculated Rate Year distribution revenue at present rates of $883.667 million.[44] Since the Authority accepted the Company's sales forecast, no change to the rate revenue at present rates is needed.

b. Other Revenues

CL&P forecasted an increase in "other" operating revenues from $22.038 million in the Test Year to $22.221 million in the Rate Year, a total increase of approximately $183,000. The Company showed that this is primarily due to an expected increase in revenue related to increasing the pole attachment rental rates. Schedule WPC-3.1. The following table illustrates the breakdown of Rate Year other revenues.

[44] There is a slight discrepancy of $6,000 in CL&P's distribution revenue at present rates shown in the C-Schedules vs. the E-Schedules.

Table 70

OTHER REVENUES - RATE YEAR ENDING 2015		
Amounts in $000's		
Account	**Description**	**Amount**
450.01	Late Payment Charge	$ 6,994
450.04	Other Late Payment Charge	2,371
	Forfeited Discounts	$ 9,365
451.01	Reconnect Fees	$ 734
451.02	Return Check Charges	328
	Misc. Service Revenues	$ 1,062
454.01	Intercompany Rent/Lease	$ 104
454.99	Rent from Elec Property (Other)	10,912
456.51	Other Facilities Charge Revenue	41
456.99	Other Electric Revenue	737
	Rent From Electric Property	$ 11,794
	Total Rate Year	$ 22,221

Response to Interrogatory RA-11, Attachment 1.

i. Late Payment Charge / Reconnection Fee Revenue

Late payment charge revenue is generated by the Company by charging 1% on a customer's delinquent balance. Revenue from reconnect fees consists of two charges: a reconnect at meter charge of $35 and a reconnect at pole charge of $60. These service charges are listed in Appendix A of the Terms and Conditions for Delivery Service, and have been in effect throughout the period 2008-2013.

Table 71

The Connecticut Light and Power Company						
Annual Company Revenue for Late Payment Charges and Reconnection Fees						
(Amounts in Dollars)						
	2008	**2009**	**2010**	**2011**	**2012**	**2013**
1.) Late Payment Charges (a/c 450)	7,713,350	8,908,561	9,590,315	6,097,963	8,269,604	9,365,076
2.) Reconnect Fees (a/c 451)	334,530	763,935	1,757,841	1,033,975	1,081,085	734,182
Total	8,047,880	9,672,496	11,348,156	7,131,938	9,350,689	10,099,258

Response to Interrogatory RA-10.

The Authority finds the proposed revenues associated with late payment charges to be reasonable. However, the rate year revenues for reconnect fees for 2013 are low compared to prior years, and should not be used as the basis for forecasting Rate Year revenue. The five-year average of reconnection revenue shown in the table above based on current charges is $1,074,204. As noted in Section II.J.8, Tariff Changes, the Authority is requiring that CL&P increase the charge for reconnection at the meter from

$35 to $42, a 20% increase, instead of the Company's proposal to lower the charge to $31. The Company is also proposing to increase the charges substantially for reconnections at the pole, by more than 100%. The Authority will adjust the Company's proposed revenue for reconnection fees to $1,350,000, which reflects the 5-year average through 2013 and approximately 25% in additional revenue expected from the increase in the reconnection charges. Therefore, other revenues will be increased by $615,818 as a result of the adjustment to reconnect fees.

ii. Pole Attachment Revenue

The OCC recommended that the Authority impute $275,260 of revenue to CL&P's Rate Year related to amount of annual pole attachment revenue it contends CL&P should receive from Verizon in the portion of Greenwich where CL&P and Verizon are joint pole owners. The OCC's recommendation is based on the following:

- CL&P has an agreement with Verizon that gives all recurring attachment revenues for jointly owned poles to Verizon.

- With ratepayer funding, CL&P pays for its share of the capital costs for all poles it jointly owns with Verizon. CL&P is also the custodian of more than 60% of the poles that it jointly owns with Verizon, and CL&P pays for O&M associated with its designated custodial poles.

- CL&P receives none of the revenue collected from attachers in the communications gain on the poles it owns jointly with Verizon.

Consequently, the OCC argued that because ratepayers share capital and custodial costs, they should share in the revenue associated with their jointly owned poles. Response to Interrogatory OCC-360; OCC Brief, pp. 109-111.

CL&P indicated that the 1956 contract between CL&P and Verizon's predecessor (the New York Telephone Company), which pre-dates the existence of cable television and fiber pole attachments, does not allow CL&P to retain any of the revenues from such attachments in the communications gain space on jointly owned poles. Responses to Interrogatories OCC-209 and OCC-360. Therefore, CL&P currently has no legal entitlement or mechanism through which to recover it from Verizon. CL&P Reply Brief, pp. 61 and 62.

The OCC also recommended that the Authority impute $1.946 million into Rate Year revenue, which reflects the amount of make-ready expense CL&P incurred in the test year that it did not recover from pole attachers. The OCC's recommendation for cost recovery is based on the following:

1. The communications gain on the pole is used by telecom/cable attachers for their service provision.

2. Code compliance work in the communications gain is necessitated by having the attachers' equipment in the communications gain. The attachers are the beneficiaries and the cost causers of the code compliance work.

3. While Telecom/cable companies should be allowed to attach to utility poles, the OCC is unaware of any statutory or regulatory requirement that electric ratepayers must subsidize their attachment.

4. CL&P should be made whole for make-ready costs by the attachers, who are the cost causers, not by the CL&P ratepayers.

For the future, the OCC recommended that the Authority direct the Company to develop a recurring or non-recurring rate for the attachers that provides the revenues necessary to reimburse CL&P fully for the cost of make-ready work in the communications gain. OCC Brief, pp. 111 and 112.

CL&P indicated that it does not have explicit permission from the Authority to recover these specific make-ready costs from pole attachers. CL&P agreed with the OCC's statements that "the OCC is unaware of any statutory or regulatory requirement that electric ratepayers must subsidize their attachment" and "CL&P should be made whole for make-ready costs by the attachers." However, the OCC's proposed increase to CL&P's rate year revenues cannot be made unless CL&P receives permission from the Authority in this case to recover this specific type of make-ready expense from pole attachers. Reply Brief, pp. 62.

The Authority will not impute revenue associated with the poles that it jointly owns with Verizon. Although CL&P is responsible for some O&M on these joint poles without full compensation, it is limited in nature to inspection and fixing damage arising from outside sources. It is unclear what the costs associated with the O&M activities are and what the real revenue deficiency is. In any event, it appears in either case that CL&P has no legal means at this time to collect revenue from Verizon under the Agreement. Imputing a revenue estimate into rates would serve to penalize the Company. The Authority finds CL&P's actions here do not warrant the penalty proposed by the OCC. The Authority will require CL&P to address this issue in the pole attachment working group meetings ordered pursuant to the October 8, 2014 Decision in Docket No. 11-03-07, DPUC Investigation into the Appointment of a Third Party Statewide Utility Telephone Pole Administrator for the State of Connecticut. The Company will be directed to report back to the Authority with a proposal that addresses the OCC's concerns.

The Authority also finds that the Company is billing properly for make-ready work under existing Authority guidelines and, therefore, will not impute revenue associated with make-ready revenue shortfalls proposed by the OCC. Not all make-ready costs are the responsibility of the attacher, such as when a new attachment is requested and the electric distribution company finds in its survey that there is a national electric safety code violation and takes corrective action.

As discussed in Section II.J.6, Pole Attachment Rates, the Authority lowered CL&Ps proposed CATV Rate from $16.56 to $13.19 and the proposed Telecom Rates were lowered from $16.56 to $13.82 and $13.89 for urban and rural attachments, respectively. The Authority could not calculate the resultant adjustment to Rent from Electric Property, Account No. 45499, as the billing determinants for pole attachments is not available. Since the adjustment will decrease Other Revenues, the Company shall include the adjustment in distribution revenue when designing rates.

c. Summary of Changes

Based on the adjustments made to other revenue herein, the initial change to Rate Year revenue will be an increase of $615,818. This increase will be offset by the reduction in in pole attachment revenue discussed in Section II.J.2.b, Pole Attachment Revenue.

3. 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 recent rate case Decisions. As has been the case historically, residential class ROR have fallen well below the overall system average ROR while commercial and industrial class RORs have exceeded system average significantly. The Company relied on its COSS results when designing rates. Effectively, the Company's proposed rates move all rate classes closer to the system average ROR. Davis, PFT, p. 8.

Wal-Mart took no position on the Company's filed COSS, other than to endorse its use for establishing rates. Wal-Mart stated that COSS-derived rates reflect cost causation, send proper price signals and minimize price distortions. Chriss PFT, p. 19.

The OCC found fault with many of the COSS allocation methodologies employed by the Company. According to the OCC:

1. The minimum distribution system study should be rejected, while distribution costs incurred for poles, lines and transformers should be classified as demand-related.

2. A quarter of transformer costs should be allocated on the basis of usage.

3. Uncollectible expense and operating expenses for customer service and information should be allocated on the basis of class revenues.

Since the OCC considered the COSS to be too impaired to be used to assign revenue responsibility among rate classes, the OCC recommended that bundled, equal percentage revenues increases be applied to all but the smallest rate classes. Should the Authority rely on the COSS, the OCC recommended that the rate of movement to rate class equality be tempered. Johnson PFT, p. 4.

The OCC also argued that poles and conductors should be classified as 100% demand-related based in large part on a population density argument. In densely populated areas found in Connecticut, utilities tend to oversize conductors when they are installed initially. As such, the incremental cost of adding new customers is minimal because neither new poles nor new conductors are required. Consequently, the cost characteristics of poles and conductors are not consistent with the partial customer classification utilized by the Company. Johnson PFT, p. 17.

The OCC also stated that since minimum system studies contain a certain load-carrying capability, they incorrectly allocate a segment of conductors on the basis of customers. As such, a zero-intercept approach to determining minimum system costs is superior. Finally, the OCC supported classifying transformers as 76% demand and 24% energy. While the typical classification is between demand and customer, the OCC argued that a new operating standard established by the FERC designed to save energy losses in transformers warrants substituting an energy classification for the customer classification. Johnson PFT, pp. 19-21.

The CIEC argued against the OCC's COSS recommendations. The CIEC stated that the COSS methodology adopted by the Company is consistent with the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual (NARUC Manual) and historical treatment approved by the Authority. CIEC Brief, p. 3. The CIEC pointed out that the NARUC Manual requires plant installed to service customers and meet their peak demand, must be segmented into customer and demand related costs. Concerning Accounts 364 through 368, the NARUC Manual at page 90 states that:

> [these accounts] involve *demand and customer costs*. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system … each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

CIEC Brief, p. 5.

The NARUC Manual recommended that either the minimum intercept method or other methods like the minimum distribution system method be undertaken to discern customer and demand cost components. CIEC Brief, pp. 4 and 5. Continuing, the CIEC quoted earlier Authority Decisions that supported the use of a customer classification.

> The Authority further held in Docket No. 90-12-03, *Application of the Connecticut Light and Power Company to Amend Rate Schedules Phase*

> *II,* in order to achieve an appropriate allocation of distribution plant, "the simplicity of the minimum-size methodology together with its producing results similar to the much more complex minimum-intercept methodology, warrants its continued use by CL&P in future COSSs."[45] The Authority determined that "a genuine, but minimal, distribution system is necessary for a utility to stand ready at no load or to serve nominal loads."

CIEC Brief, p. 9.

The CIEC also provided supportive Authority language used in other electric rate cases stating that:

> The Authority has continued to reaffirm its position. In Docket No. 05-06-04, *Application of the United Illuminating Company to Increase its Rates and Charges*, the Authority rejected the OCC's recommendations that no costs be allocated based on the number of customers.[46] Similarly, in Docket No. 08-07-04, *Application of the United Illuminating Company to Increase its Rates and Charges*, the Authority held that the "OCC has provided no compelling reason to deviate from these established standards"[47] and rejected its request for allocation on the basis of demand only.[48] The OCC's repetition of these repeatedly rejected arguments in this Docket is without support and should be rejected.

CIEC Brief, p. 10

The Authority finds that the population density argument for allocating poles and lines fully on demand is tortured at best. Poles and lines are installed to expand circuits to reach new off-circuit customers. Poles and lines are also required to provide service to new customers situating along existing circuits; albeit not new poles and lines. Regardless of whether pole and lines are new or existing, circuits require both to reach customers. Additionally, it is hard to visualize a demand component to a pole. Demand components exist for poles through the formalistic design of minimum system theory much more than in the practical world of circuit design. Lines or cables have both a customer and demand component. While some minimum size cable is necessary to simply reach all customers, kVA levels differ dramatically between residential neighborhoods and industrial parks.

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[45] Docket No. 90-12-03, Application of The Connecticut Light and Power Company to Amend Rate Schedules Phase II, Final Decision (August 1, 1991) Lexis Version at 36.

[46] Docket No. 05-06-04, Application of The United Illuminating Company to Increase its Rates and Charges, Decision (issued January 27, 2006) at 114.

[47] Docket No. 08-07-04, Application of The United Illuminating Company to Increase its Rates and Charges, Final Decision (February 4, 2009) at 107-108.

[48] The Authority has also rejected the application of a demand only to gas plant. Specifically, in its Decision dated June 29, 2011 in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules, the Authority held that "[t]he OCC's conclusion that trenching costs, 2/3 of current installation costs, should be allocated on peak day demand because of some statistical result defies common sense." Decision, p. 156.

Transformers also have a customer and demand component since transformers are needed to expand circuits to reach customers and sized to reflect differing kVA demands. While the OCC argued that the new efficiency performance standards reduce energy losses, transformers are still sized to satisfy diversified neighborhood peak kVA. The newer transformers will simply provide this service with less energy lost as heat. Additionally, the 24% portion that the OCC proposed to allocate on energy represents the increased cost of a transformer. It does not represent the minor reduction in heat loss actually achieved by the new standard. Johnson PFT, p. 26.

The Company proposed to allocate uncollectible expenses of $5.2 million on the basis of the actual net write-off per rate class. This methodology assigns approximately 82% of the cost to residential rates. Late Filed Exhibit No. 7. The OCC recommended an allocation of uncollectible expense on the basis of class revenues as it is a social cost, and should be spread broadly across the customer base. The magnitude of the uncollectible expense in a given period is affected not only by the number of customers on the system, but also by the amount of revenue billing attributable to each particular type of customer. In addition, the potential for significant impact from individual large accounts should be considered. Direct assignment of the cost does not allocate the expense to cost causers, because the non-payers, by definition, are not paying customers. Therefore, the expense is a social cost which should be spread on a general allocator like revenues. Johnson PFT, pp. 29 and 30.

At the hearing on August 28, 2014, the Authority introduced the concept of allocating uncollectible expense on a socialized, or 100% customer basis. Effectively, every customer would pay the same monthly fee. Tr. 8/28/14, p. 351. In response to cross examination, the Company filed Late Filed Exhibit No. 7, which indicated that under this approach, residential rates would be assigned 90% of the total cost. The Authority accepts the Company's method of allocating uncollectible expense, which utilizes the same methodology approved in recent rate cases. While socialization is a valuable approach, it can wait until a future rate application to be implemented. The Authority may undertake a full COSS and rate design generic review to establish a standardized methodology.

The Authority accepts the COSS submitted by the Company and will rely on it to address rate design issues. The Company's methodology has been consistently applied and approved in multiple rate increase applications and the arguments presented mainly by the OCC have been examined before. Nonetheless, the Company will be directed to submit a zero-intercept study for determining the customer and demand components of various plant accounts in its next rate increase application.

4. Revenue Allocation

a. Company Proposal

The Company allocated revenue increases and determined distribution revenue targets for each rate class based on an evaluation of the excess or deficiency identified in the COSS of each rate class. In general, to reduce the amount of excess or deficiency, and accordingly move the class ROR closer to the equalized ROR, classes with a deficiency (e.g., Rates 1 and 7, defined below) received an increase to their current distribution revenue increase that was greater than the Company-average of 26.2%. Classes with a revenue excess (e.g., Rates 27, 30, 35, 37, 55-58, defined below) received an increase that was less than the average. Unmetered classes (particularly the street lighting classes for which significant structural redesign and specific other rate design constraints apply) received an increase at or near the Company average. Davis PFT, p. 10.

Based on its proposed rate request, the Company proposed the following Rate class rate increases:

Table 72

Rate	Schedule/Description	2015 Forecasted Sales (mWh)	Current Revenue	Current $kwh	Proposed Revenue	Proposed $kwh	% Change Proposed vs. Current
1	Residential - Regular	8,461,362	$ 1,556,750	0.1840	$ 1,704,998	0.2015	9.52%
5	Residential - Electric Heat Regular	1,828,279	$ 321,999	0.1761	$ 345,692	0.1891	7.36%
7	Residential - Time-Of-Day	6,156	$ 1,071	0.1740	$ 1,153	0.1874	7.70%
18	Controlled Water Heating *	878	$ 147	0.1674	$ 158	0.1801	7.56%
27	Time-Of-Day General	13,961	$ 2,632	0.1885	$ 2,786	0.1996	5.88%
29	Outdoor Lighting	3,232	$ 775	0.2399	$ 856	0.2647	10.33%
30	Small General	3,275,128	$ 596,593	0.1822	$ 624,316	0.1906	4.65%
35	Intermediate General	1,148,500	$ 179,744	0.1565	$ 184,151	0.1603	2.45%
37	Intermediate Time-Of-Day	1,285,729	$ 195,975	0.1524	$ 201,421	0.1567	2.78%
39	Interruptible Menu	235,489	$ 23,020	0.0978	$ 23,286	0.0989	1.15%
40	Church and School	115,402	$ 20,212	0.1751	$ 21,368	0.1852	5.72%
41	Large Church and School	15,096	$ 2,579	0.1709	$ 2,654	0.1758	2.88%
55	Intermediate TOD Manufacturers	674,097	$ 84,700	0.1256	$ 86,746	0.1287	2.42%
56	Intermediate TOD Non-Manufacturers	2,032,033	$ 264,026	0.1299	$ 270,403	0.1331	2.42%
57	Large TOD Manufacturers	1,077,844	$ 125,898	0.1168	$ 128,122	0.1189	1.77%
58	Large TOD Non-Manufacturers	2,052,918	$ 250,402	0.1220	$ 255,608	0.1245	2.08%
115	Unmetered	53,500	$ 8,820	0.1649	$ 9,425	0.1762	6.86%
116	Street & Security Lighting	92,563	$ 24,445	0.2641	$ 27,884	0.3012	14.07%
117	Partial Street Lighting Service	23,425	$ 3,380	0.1443	$ 3,622	0.1546	7.16%
119	Special Contracts	1,320	$ 492	0.3731	$ 558	0.4226	13.25%
	Total	22,396,911	$ 3,663,662	0.1636	$ 3,895,206	$ 0.1739	6.32%

Exhibit EAD-15, p. 3.

To determine a fair and equitable revenue allocation, the Company considers each rate class' ROR relative to the system average ROR to measure where the excesses/deficiencies exist. The following table illustrates each rate class' existing contribution to overall system ROR.

Table 73

Rate	Class ROR	Rate	Class ROR
1 & 7	1.10%	41	17.12%
5	2.87%	55	11.97%
18	-0.38%	56	13.17%
29	6.17%	57	12.39%
27 & 30	10.47%	58	12.44%
40	6.81%	115	4.45%
35 & 37	12.59%	116 & 117	0.50%
39	6.01%	Special Contracts	7.79%
	* Current System ROR (Company) = 4.16%		
	**Approved System ROR (Company) = 7.24%		

Exhibit EAD 17, pp. 3 and 4.

b. OCC Proposal

The OCC indicated that while the COSS provides useful information for developing the class revenue increases, it should not be the sole consideration. Non-cost considerations are appropriate in mitigating pure COSS results. Further, COSS are imprecise instruments. COSS allocate costs to a multiple decimal point level, which could provide a false sense of security about the accuracy of the studies. This conclusion is based on two general reservations regarding embedded COSS. First, some of the costs are classified and allocated on a weak causal basis, and subjective judgment enters into the selection and development of allocation methods. Second, COSS are a static snapshot of the dynamic relationship between supply and demand. Both costs and class usage characteristics will change over various long-run time periods. For these reasons, some degree of judgment may be appropriate in applying the COSS to class revenue increases. “Cost based rates” are best viewed as representing a reasonable band around the COSS results, rather than exact price points. Furthermore, COSS which do not recognize the differences in risk associated with customer classes should be utilized cautiously. Johnson PFT, pp. 40-47

The OCC also disagreed that all classes should be targeted to produce equalized RORs. The Company’s required ROR is dependent upon the perceived financial and business risk of the public utility. If the composition of sales by customer class has the effect of producing differing business risks to the utility, then the rationale for equalized relative ROR is not sound. In that situation, it is no more reasonable to expect equal relative contributions to return than it would be to expect all stocks in a portfolio to make equal contributions to the overall ROR of the portfolio. Id.

The OCC noted that industrial customers are generally riskier to serve due to the larger capital investment required to serve each customer, and the revenue impact from customer losses. Industrial customers' load is more dependent upon domestic or international market conditions. Distributed generation installed by large businesses, as well as manufacturing shutdowns or declining production, reduce the revenue generating capability of distribution plant and ultimately shifts costs onto the more stable residential class. Therefore, the residential class should be expected to produce a lower relative ROR and industrial customers a higher one. Since the revenue targets produced by a COSS presume uniform class RORs, this is an inherent weakness in the practice of strictly moving toward the class RORs in the COSS. Id.

The OCC suggested that several non-cost considerations counterbalance the COSS. First, the COSS does not take into account the risk differences among the classes. Second, the customer class cost relationships are more complicated than the COSS implies. Third, CL&P's current residential rates are very high, and implementing an above system average percent increase on the residential class will exacerbate the situation. According to the Energy Information Administration, Connecticut has the second highest residential electric rate in the United States (behind only Hawaii). Id.

The OCC pointed out that there are a number of bill items that impact distribution, but are recovered in other billing categories, such as non-bypassable federally mandated congestion charges (NBFMCC). In the OCC's view, these bill items feature: (a) cross subsidization among the rate classes; (b) charges for programs that impact distribution rates; and (c) costs that should properly be charged to distribution. Examples of this include the following.

- The DG program: This program includes payment of gas distribution charges and waiver of backup charges for the large user participants. Most of the ratepayers who pay the cost of this subsidy do not qualify for participation in the program. In addition, DG program participants greatly reduce their usage of electricity, leaving the remaining ratepayers to shoulder the share of distribution costs previously supported by the DG participants.
- Storm resiliency: In this case, CL&P includes an additional $44 million for resiliency that it would charge to NBFMCC until the next rate case after this one. CL&P has also charged resiliency costs to NBFMCC in a pending proceeding (Docket No. 14-02-01, PURA Semi-Annual Reconciliation of the Federally Mandated Congestion Cost and Generation Service Charges of The Connecticut Light and Power Company and The United Illuminating Company). Residential customers pay a disproportionate amount of NBFMCC costs, and distribution costs previously recovered from residential users through the NBFMCC appear to reflect equalized rates of return. Because the charges were outside the COSS, residential customers do not receive credit in the COSS results for the returns paid through the NBFMCC.

Id.

Additionally, the OCC stated that CL&P's proposed distribution percentage revenue changes are much higher for residential customers than commercial and industrial (C&I) customers. The OCC recommended setting the increase 120% higher than the system average percent increase for the following Rates: 18, 25, 39, 116, 117, and 119. The OCC further recommended distributing the remaining portion of the revenue increase on an equal percentage basis to the remaining classes (6.2% based on the Company's filed request). Capital investments for resiliency, upgrading distribution facilities, and replacement of outdated distribution infrastructure are among the drivers of the increased rates. All customer classes should contribute to the rate increases supporting these upgrades on an equivalent basis. The OCC stated that, even assuming that the proposed rate increases rely on the COSS targets, CL&P's proposed class revenue increases represent movement that is too rapid and produces excessive rate impacts on residential customers. The alternative COSS proposed by the OCC reduced the residential revenue deficiency by almost 40%. Given the reduction in the residential target, the severity of the proposed movement to cost of service for below-cost classes can be relaxed. Id.

As an alternative to its proposal, the OCC recommended the following revenue increase allocation parameters: set the residential total bill revenue increase no higher than 118% of the system average percentage (approximately a 7.5% percent increase based on the Company's filed request); limit all below-cost class increases to 120% of system average; and set a floor of 75% of system average percent for all above-cost classes. This would produce a 28% increase in distribution revenues for the residential class or approximately 110% of the system average distribution increase, which would represent reasonable movement toward the COSS results, particularly taking into account the adjustments recommended for the COSS methodology. Id.

c. Position of the Parties

In addition to the positions/alternative proposal offered by the OCC above, the CIEC and the BETP provided comments specific to revenue allocation.

i. Connecticut Industrial Energy Consumers

The CIEC indicated that the RORs of the residential classes are significantly below the system average. In contrast, rates imposed upon C&I rate classes provide above-average ROR. As a result, the C&I classes are subsidizing the residential classes and providing, in most instances, RORs, at current rates of approximately three times the system average. The total subsidy paid by C&I classes under current rates exceeds $20 million annually. Undoubtedly, over the past decade, large C&I customers have paid tens of millions of dollars in excess of their actual cost of service. In order to continue to promote rate unity and properly allocate distribution costs among rate classes, the Company's allocation should be approved. CIEC Brief, pp. 15 and 16.

ii. Bureau of Energy & Technology Policy

The BETP is concerned with the proposed allocation of the overall rate increase among CL&P's customers and recommended narrowing the difference between the average increase for different rate classes, especially for residential and street lighting customers. CL&P's COSS should be regarded as a guide to ratemaking, but not the only factor considered. Other important factors that must be considered are rate impacts, equity, continuity, efficiency, and understandability. The BETP disagrees with CL&P that the ROR for each rate class should be equal. Electricity use for residential customers is more predictable than C&I customers, whose usage is much more affected by economic trends. The BETP recommended lowering the overall increase to Residential Rate 1 and Street Lighting Rate 116 customers to no more than 125% of the average rate increase for all customers to reduce the burden on residential customers and municipalities. BETP Brief, pp. 10-13.

d. Authority Analysis

The Company's COSS will be relied upon by the Authority for designing rates. The Authority finds that to reduce interclass subsidies, all classes should be moved closer to their cost to serve, or closer to the system average ROR, while applying the principles of rate gradualism. While gradualism is certainly a debatable concept, the Authority considers the impacts on each rate class relative to the system revenue increase approved herein. The approved revenue requirement increase of $130.172 million will increase the current total revenues of $3,663 million by approximately 3.5%. See, Table 74. Since the Authority is allowing a total system-wide rate increase of approximately 3.5%, it would suggest that the rate classes that are contributing a lower relative return will be allocated a revenue requirement increase in excess of that amount, and vice versa for higher contributing classes. The farther the class is from the system average, the larger the percentage increase/decrease necessary to align the class revenues to the average.

The Company demonstrated, through the results of its COSS, the need to assign a higher proportion of the distribution rate increase to Rates 1, 7, 5, 18, 115, 116 and 117 and a lower portion of the rate increase to rates 27, 30, 35, 37, 41, 55, 56, 57 and 58. This determination was made through analysis of each rate class' current contribution to the Company's revenue requirements. As shown, Rates 1, 7, 5, 18, 115, 116 and 117 are contributing a ROR that is at least 200% lower than the system ROR. Rates 27, 30, 35, 37, 41, 55, 56, 57 and 58 have a class ROR that is at least 200% higher than the system ROR. To reduce inequities between classes, it is necessary to align the rate classes as close to the system ROR as possible.

The Authority accepts the Company's proposed allocation methodology of its rate request among the customer classes. CL&P has provided a reasonable proposal which is generally fair to all rate classes while moving the RORs closer to the Company's average. The Company allocated a higher than average (6.35%) increase to Rates 1, 5, 7, 18, 29, 115, 116, 117 and 119, which are the rate classes showing the lower than system RORs in the COSS. Conversely, the Company allocated a lower than average increase to Rates 27, 30, 35, 37, 39, 40, 41, 55, 56, 57 and 58. The proposed allocation appropriately shifts more revenue responsibility to the residential customer class while keeping the rate increase to approximately 50% greater than the average, which the Authority does not view as excessive, given the current ROR of 1.1%. The highest increases of 14.07% and 13.25% are proposed for the low volume Street &

Security Lighting and Special Contract classes, again, not excessive relative to the overall increase and their current ROR of 0.50%.

The allowed increase (not including the ROE penalty) is approximately $96 million less than the Company's original proposal of $231.6 million, on which they based their rate design proposal. Therefore, the revenue allocation to the individual rate classes will change as a result of the Authority's reduction to CL&Ps proposal. To maintain the equity balance previously discussed, the Authority will apply the adjustment to the proposed revenue increase to the rate classes by holding intact each rate class' overall percentage increase relative to the average percentage increase for all customers from CL&P's original proposal. For example, for Rate 1, CL&P proposed an overall percentage increase of 9.52%, which is 51% higher than the overall proposed rate increase of 6.32%. By holding the relationship of the increase to Rate 1 relative to the overall allowed increase of 3.51%, the adjusted increase for Rate 1 is 5.51%. The following table details this methodology applied to all of CL&P's rate classes[49]:

Table 74

Rate Year Revenue and Rate Class Allocation

			(A)		(B)			{C)	(D)		{E)	(F)	(G)
											Authority Adjustment		
		2015 Forecasted	Current		Proposed			% Change Proposed	Rate Class to average %		% Allowed Vs. Current	Allowed Revenue	Adjustment $
Rate	Schedule/Description	Sales (mWh)	Revenue	$kwh	Revenue	$kwh		**B / A-1**	**(C) / (H)**		**D * I**	**(E+1)*A**	**(F)-(B)**
1	Residential - Regular	8,461,362	$ 1,556,750	0.1840	$ 1,704,998	0.2015		9.52%	151%		5.51%	$ 1,642,522	$ (62,476)
5	Residential - Electric Heat	1,828,279	$ 321,999	0.1761	$ 345,692	0.1891		7.36%	116%		4.26%	$ 335,707	$ (9,985)
7	Residential - Time-Of-Day	6,156	$ 1,071	0.1740	$ 1,153	0.1874		7.70%	122%		4.45%	$ 1,119	$ (35)
18	Controlled Water Heating *	878	$ 147	0.1674	$ 158	0.1801		7.56%	120%		4.37%	$ 153	$ (5)
27	Time-Of-Day General	13,961	$ 2,632	0.1885	$ 2,786	0.1996		5.88%	93%		3.40%	$ 2,721	$ (65)
29	Outdoor Lighting	3,232	$ 775	0.2399	$ 856	0.2647		10.33%	163%		5.98%	$ 822	$ (34)
30	Small General	3,275,128	$ 596,593	0.1822	$ 624,316	0.1906		4.65%	74%		2.69%	$ 612,633	$ (11,683)
35	Intermediate General	1,148,500	$ 179,744	0.1565	$ 184,151	0.1603		2.45%	39%		1.42%	$ 182,294	$ (1,858)
37	Intermediate Time-Of-Day	1,285,729	$ 195,975	0.1524	$ 201,421	0.1567		2.78%	44%		1.61%	$ 199,126	$ (2,295)
39	Interruptible Menu	235,489	$ 23,020	0.0978	$ 23,286	0.0989		1.15%	18%		0.67%	$ 23,174	$ (112)
40	Church and School	115,402	$ 20,212	0.1751	$ 21,368	0.1852		5.72%	91%		3.31%	$ 20,881	$ (487)
41	Large Church and School	15,096	$ 2,579	0.1709	$ 2,654	0.1758		2.88%	46%		1.67%	$ 2,622	$ (31)
55	Intermediate TOD Manufacturers	674,097	$ 84,700	0.1256	$ 86,746	0.1287		2.42%	38%		1.40%	$ 85,884	$ (862)
56	Intermediate TOD Non-Manufacturers	2,032,033	$ 264,026	0.1299	$ 270,403	0.1331		2.42%	38%		1.40%	$ 267,715	$ (2,687)
57	Large TOD Manufacturers	1,077,844	$ 125,898	0.1168	$ 128,122	0.1189		1.77%	28%		1.02%	$ 127,185	$ (937)
58	Large TOD Non-Manufacturers	2,052,918	$ 250,402	0.1220	$ 255,608	0.1245		2.08%	33%		1.20%	$ 253,414	$ (2,194)
115	Unmetered	53,500	$ 8,820	0.1649	$ 9,425	0.1762		6.86%	109%		3.97%	$ 9,170	$ (255)
116	Street & Security Lighting	92,563	$ 24,445	0.2641	$ 27,884	0.3012		14.07%	223%		8.14%	$ 26,435	$ (1,449)
117	Partial Street Lighting Service	23,425	$ 3,380	0.1443	$ 3,622	0.1546		7.16%	113%		4.14%	$ 3,520	$ (102)
119	Special Contracts	1,320	$ 492	0.3731	$ 558	0.4226		13.25%	210%		7.66%	$ 530	$ (27)
													$ -
	Total	22,396,911	$ 3,663,662	0.1636	$ 3,895,206	$0.1739	**(H)**	6.32%	100%	**(I)**	3.66%	$ 3,797,627	**$ (97,580)**
											I = (B+M)/A-1		
		(J)	Company Request (Application)		$ 231,545								
		(K)	Allowed Rate Increase		$ 134,565								
		(L)	Increase in Other Revenue		$ 600								
		(M)	Adjustment to Rate Revenue		**$ (97,580)**	=	**(J-K)+L**						

The Authority notes that the transfer of $15.3 million of system resiliency expenses will reduce the overall increase once it is implemented. Because the system resiliency charges will not be removed from the NBFMCC charge until it is reset in January, the Company shall return to customers the system resiliency-related revenues it collects through the NBFMCC in December 2014.

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49 The Authority made further adjustments to the approved revenue requirement for 2016 previously established in the Proposed Final Decision of approximately $489,000. In Section II.J.5., Rate Design, the Authority directs the Company to allocate the net decrease to Rate 116.

5. Rate Design

a. Company Proposal

The Company proposed rate changes that are designed to recover its Rate Year distribution operating deficiency and previously approved storm costs and system resiliency costs commencing on December 1, 2014. The Company developed the proposed distribution rates by allocating the revenue increases and designing rates for each rate class in a manner that achieves a balance among a number of interrelated objectives, based on an evaluation of the cost of service, current rates and impacts of changes to rates in each class. In particular, the Company sought to move rates in each rate class closer to their actual cost of service, both at a total class level and with respect to the prices for distribution service within each rate class. By applying the principles of equity and cost causation in allocating cost responsibility among rate classes, as well as the principle of gradualism in setting total class revenues, the Company reduced the revenue excess or deficiency and moved the ROR for each rate class closer to the Company average. Those rate classes with below system average RORs (as computed within the COSS based on current rates) have been allocated a greater than average percentage distribution increase, while those classes with above system average RORs have been allocated a lower than average percentage increase. Davis PFT, pp. 1-3.

CL&P indicated that its rate design also moves current rates closer to cost-of-service levels within rate classes by generally decreasing or eliminating per kWh charges, and moving customer and demand charge rates closer to their cost-of-service levels. The Company redesigned residential and small general service customer rates based on the COSS. Specifically, these rates were redesigned to increase the amount of distribution costs collected through customer charges and, where applicable, demand charges, and thereby reduce the recovery of fixed distribution costs through volumetric charges. In redesigning specific rates within each class, application of these principles more equitably align the recovery of fixed distribution costs with an appropriate, corresponding rate mechanism. Id.

Overall, the proposed rates were designed to collect a total distribution revenue increase of $231.6 million, and when combined with a corresponding reduction of $15.3 million to the NBFMCC, will represent an overall average increase to total bills of 5.9%. Id. CL&P proposed to move the ROR of each rate class closer to the Company's average ROR, and reduce the amount of fixed distribution costs recovered through volumetric charges. The Company gave additional consideration to the allocation of costs and redesign of rates within the street lighting class due to its proposed structural changes. CL&P asserted that its proposal achieves a balance between assigning an appropriate level of cost responsibility to each rate class, maintaining reasonable bounds around rate changes and customer impacts, and addressing fixed cost recovery through rates as appropriate. Davis PFT, p. 8.

CL&P proposed the following rate design changes for the residential classes:

Table 75

Comparison of Current Rates vs Proposed Rates				
	Current	Proposed	Proposed vs. Current	
	Rate	Rate	Difference	% Chg
Rate 1 - Residential Electric Service				
Customer Charge	$16.00	$25.50	$9.50	59.38%
Energy Charge All kWh	$0.16165	$0.16591	$0.00426	2.64%
Rate 5 - Residential Electric-Heat				
Customer Charge	$20.25	$30.00	$9.75	48.15%
Energy Charge All kWh	$0.15768	$0.16176	$0.00408	2.59%
Rate 6 - Residential Electric Heat TOD				
Customer Charge	$20.25	$30.00	$9.75	48.15%
Energy Charge On-Peak kWh	$0.15768	$0.18496	$0.02728	17.30%
Energy Charge Off-Peak kWh	$0.15768	$0.14996	($0.00772)	-4.90%
Rate 7 - Residential TOD				
Customer Charge	$16.00	$25.50	$9.50	59.38%
Energy Charge On-Peak kWh	$0.18485	$0.18911	$0.00426	2.30%
Energy Charge Off-Peak kWh	$0.14985	$0.15411	$0.00426	2.84%

Application, Exhibit EAD-3.

For Rate 1, CL&P set a distribution rate revenue target of $570.4 million, an increase of $148.2 million or 35.11% over its current distribution revenue of $422.5 million. Application, Exhibit EAD-2. CL&P also proposed to collect the increase through a 59% increase to the Rate 1 Customer Charge and a 2.64% increase to the per-kWh Charge.

b. Office of Consumer Counsel Proposal

The OCC disagreed that the Company's proposed customer charge is cost-based. This relates to the OCC's assertion that the Company's COSS is faulty, particularly with respect to the classification of distribution infrastructure as customer-related. If the COSS classified distribution facilities on a full demand basis, without classifying the plant costs as customer-related, the study would support a customer charge no higher than $11.68. Therefore, both the current and proposed customer charges are above cost. Even among those utilities that utilize a minimum system study for the COSS, it is rare that the customer charge is fixed at a level which recovers the cost of secondary and primary voltage conductors, poles, and transformers. Further, the fact that the law now requires a revenue decoupling mechanism should lead to the conclusion that the motivation for continued increases in fixed charges no longer exists. Johnson PFT, pp. 33-40.

The OCC proposed that the customer charge should only recover costs which directly vary with the number of customers such as: O&M expense for meters, services, meter reading, and customer accounting, and return and depreciation on meter and service investment, minus credits for customer deposits and related deferred federal income taxes. General overhead, such as administrative and general expense, should be excluded from the customer charge computation, because these costs do not vary directly with number of customers. The OCC proposed a maximum $11.68 customer charge. Id.

The OCC stated that with the exception of its access rationing role, the customer charge provides no price signal relevant to resource allocation. Because the electric utility cost structure is dominated by costs which vary with changes in demand and annual electric load, the usage-sensitive rate is the primary source of meaningful price signals. A lower customer charge ensures that a greater proportion of costs are recovered through a usage-sensitive price. A lower customer charge is more consistent with energy conservation goals and provides pricing policies appropriate for consumption of finite natural resources. In addition, a policy that minimizes the customer charge is more equitable to low usage residential customers. Many such customers often reside in older multi-family structures served by largely depreciated meters and service drops. Id.

The OCC pointed out that low-use customers in Rate 1 will face the largest percentage bill increases from the proposed customer charge increase (for instance, a 16% increase in the total bill for 300 kWh customers. According to the OCC, imposing a larger increase on customers who impose a minimal demand on the system, and may be the least capable of affording the rate increase, is inequitable. The concept of fixed vs. variable costs is not a very meaningful distinction for purposes of utility cost analysis. Inasmuch as the majority of customer usage within the residential class falls within a reasonable range of load factors, a kWh usage charge is likely to accomplish approximately the same purpose as a demand charge. Id.

The OCC recommended that the Customer Charge for Rate 1 be set no higher than $11.50, which is in line with the COSS service results. If the Authority is reluctant to reduce the customer charge, at the least, the current customer charge should not be increased. A high customer charge tends to inhibit energy conservation. Minimizing the customer charge provides the ratepayer with a greater ability to control his/her bill on the basis of usage. For that reason, an excessive customer charge can promote wasteful energy consumption. Connecticut has numerous statutory programs which provide incentives for increased energy efficiency, evincing a staunch policy in favor of reduced energy consumption. The increase in customer charge runs counter to that state policy. The OCC calculated that there is a 10% reduction in the life cycle present value savings under the Company's pricing vs. the OCC's proposed charge of $11.50. At a practical level, the lower potential savings under the Company's increased customer charge represents an extra incentive amount, which may have to be paid by state programs to achieve the expected demand reductions. Id.

c. Position of the Parties

The OCC, BETP, ENE and AG all strongly objected to the 59% increase in the customer charge. The Authority also received an unprecedented number of comments from customers, public officials and consumer advocates on the proposed rate increase. An overwhelming majority of customers who submitted public comment or testified at the public hearings or filed written comments strongly opposed the proposed rate increase, especially the 59% increase in the residential Customer Charge.

i. Office of the Attorney General

The AG commented that CL&P's proposal to increase the customer charge by 60% is unduly burdensome for residential ratepayers and is poor public policy. Further, due to the implementation of full sales decoupling in the instant proceeding, increasing the customer charge is completely unnecessary to further the intent of decoupling. AG Brief, p. 20.

ii. Office of Consumer Counsel

The OCC indicated that CL&P's rate design proposal is contrary to the state's energy policy and adversely impacts small electricity users, low-income and fixed income and elderly customers. CL&P's efforts to radically increase the customer charge is also "anti-conservation," as it attempts to shift costs currently recovered through commodity rates to fixed monthly charges that do not vary by usage levels. OCC Brief, p. 4. Further, the OCC pointed out that CL&P's Rate 1 Customer Charge is much higher than in the other New England states. The OCC urged the Authority to consider the actual impacts of this dramatic increase in CL&P's customer charge and whether those impacts are consistent with state policy, rather than adhering to an ideological path that is clearly inconsistent with state policy. OCC Brief, 115 and 116.

iii. Environment Northeast

ENE stated that the Company's proposed increases in the fixed charges do not align with Connecticut's energy efficiency and clean energy policies and, therefore, are not in the best interest of CL&P's customers. ENE supported CL&P's request for full revenue decoupling because it will help remove any Company sales-related disincentive to promote energy efficiency and distributed generation. Decoupling is also an effective cost-recovery alternative to CL&P's proposal to increase the fixed charge. ENE argued that the proposed high fixed charge increases do not align with state energy policy for several reasons: (1) they reduce customer control over electricity costs, (2) they are unfair to energy efficient (or low-use) customers (3) they reduce the value of existing efficiency or on-site generation investments, (4) they reduce the economic signal to customers to invest in energy efficiency and (5) they may harm the cost-effectiveness of the state's energy efficiency programs. ENE Brief, pp. 4-6.

ENE recommended that the Authority design rates by: (1) lowering the fixed customer charge in the residential classes to at least $11.50, as recommended by the OCC; (2) rejecting the excessive fixed charge increases in the small business and church and school customer classes; (3) applying any approved rate increase solely to the variable charges, which is the portion of the distribution bill that the customer can control; and (4) requiring CL&P to implement revenue decoupling with a full reconciliation mechanism between allowed and actual revenue. ENE Brief, p. 7.

iv. Bureau of Energy & Technology Policy

The BETP recommended that the Authority: (1) reduce CL&P's proposed fixed monthly service charge increase for all residential and small commercial customers; (2) reduce the burden on residential customers and municipalities by narrowing the difference in the average rate increase among rate classes; (3) approve CL&P's decoupling proposal; and (4) increase the rate differential for on- and off- peak charges in residential time-of-use Rate 7. The BETP indicated that the priorities outlined in the 2013 Comprehensive Energy Strategy (CES) form the basis for their recommendations, namely energy efficiency, increasing system reliability with DG and advancing the development of in-state renewable energy resources. BETP Brief, pp. 2-4.

The BETP opposed CL&P's proposed fixed monthly service charge for three main reasons. First, increasing the fixed monthly service charge unfairly penalizes certain classes of customers, specifically those customers who use the least electricity, such as small businesses, churches and schools, and people on low or fixed incomes. Second, increasing the fixed monthly service charge undermines a customer's ability to obtain the full benefits of key energy-saving programs encouraged in the 2013 CES, such as energy efficiency. Third, CL&P's proposal to increase the fixed monthly service charge works against the state's efforts to increase the deployment of in-state, local clean energy resources like solar, fuel cells, combined heat and power, and other similar technologies, as detailed in the 2013 CES. Id.

d. Authority Analysis

i. Residential

The Authority finds that applying this rate class increase in an across-the-board manner to the residential rate classes is a reasonable approach to increasing the distribution charges in a more moderate manner than the Company's proposal. The Authority fully agrees with the Company that the general objective of rate design is "to continue to move distribution rates among and within classes to better reflect the cost responsibilities identified in the Company's cost of service study." While the Authority generally prefers an approach that moves rates towards increased fixed cost recovery, it must consider the customer impact of how the rate increase is applied. The Company made a significant leap in the 2008-2009 timeframe by implementing a 60% increase in the residential Customer Charge, from $10 per month to the current charge of $16. Response to ENE-6. Further, the Authority is no longer mandated to implement decoupling through increased fixed charges, but instead required to implement full revenue decoupling. See, Section II.H, Decoupling. Given the level of customer opposition to the fixed charge design, the current Customer Charge levels and the implementation of a decoupling mechanism in the instant case, a more gradual approach is warranted. Therefore, the Authority will approve customer charge increases for Rates 1, 5 and 7 that reflect the application of the average distribution rate class increase across-the-board.

The Authority illustrates this approach in the case of Rate 1 (and TOD companion Rate 7). As shown in Table 74, the Authority lowered CL&P's proposed distribution revenue increase for Rates 1 and 7 by approximately $62.5 million, which lowers CL&P's distribution revenue target from $570.8 million to $508.3 million. The proposed distribution rate increase for Rate 1 and 7 will therefore be decreased from 35.1% to 20.3% ($508.3 million / $422.5 million in current revenue). Applying this increase in an across-the-board manner in the residential rate classes, or 20.3% in the case of Rate 1 and 7, produces a customer charge of approximately $19.25. See,

Table 75 and Application, Exhibit EAD-2, line 21. Applying the Rate 5 adjusted distribution increase of approximately 17.2% [($103.3 million - $10 million) / $79.6 million in current revenue] across-the-board will raise the customer charge from $20.25 to approximately $23.73. See, Table 75 and Application, Exhibit EAD-2, line 22. The Authority will further adjust the Rate 5 Customer Charge by rounding it to $23.75.

Several parties argued that decoupling reduces the need for large increases in fixed charges, as the Company will be assured the revenue recovery through the decoupling mechanism. Now that the Company is shielded from the effects of revenue variability due to decoupling, it is tempting to dismiss the need to continue the move towards fixed costs recovery. While that is true to some extent, the Authority cautions on the unintended consequences of over-relying on a decoupling mechanism and, consequentially, eroding cost-based ratemaking principles. In a decoupling environment, lower customer charges and higher variable charges increases ratepayers' exposure to large swings in sales related to conservation, distributed generation, weather and the economy. For example, in the event of a much warmer than normal summer, a portion of the revenue recovered from residential customers may be returned to commercial and industrial (C&I) customers.

As such, the Authority is against lowering the customer charges from current levels, or eliminating the customer charges altogether. While the Authority supports the state's energy policy goals, they do not justify abandoning well-established cost of service principles that promote customer equity and cost causation. Intentionally increasing fixed cost recovery on a volumetric basis does not reflect cost causation and misallocates demand cost responsibility, thereby increasing inequities within a class. Distribution costs do not vary in proportion to the energy delivered, but are only a function of the number of customers and their peak demands. If rates are designed in large part to maximize customers' ability to control their bill, then those costs are shifted to other customers or perhaps re-charged to the customer the following year through the decoupling mechanism. Regarding some of the Parties assertions that increasing fixed charges unfairly burdens low-use customers, the Authority notes that not increasing fixed charges has the effect of shifting that cost responsibility to the remaining customers in that rate class. In approving the overall rate design, the Authority must balance the competing interests of all customers.

Lastly, more investigation is needed regarding how customers perceive price signals, both at the overall bill level and on the billing component level. It is not clear what the magnitude of price signals will need to be to effectuate change in customer usage behavior. The Authority can use anecdotal evidence based on customer migration levels from Rate 1 to 7 that the potential for a 10% savings has not induced a large customer migration to TOD pricing.

The approved revenue requirements, revenue allocation and rate design changes discussed above will result in an increase of approximately $7.12 per month[50]

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[50] Bill impact estimate is based on a current customer bill of $129.16 for 700 Kwh of usage and an average increase of 5.51%, totaling approximately $136.28 under new rates. See, Exhibit EAD-6, p. 1.

for the average residential customer's bill. Under the approved rate design, ample opportunity remains for customers to conserve and save as the vast majority of customers charges are priced on a volumetric basis. A $19.25 Customer Charge, the only fixed component, relative to a total customer bill of $136.28 is approximately 14 percent. Therefore, approximately 86 percent of the bill remains subject to immediate savings if kWh consumption is reduced.

ii. Commercial and industrial

Many of the arguments raised by the Parties on increasing the fixed charge in the residential rate classes also apply to the smaller commercial rate classes. The following table illustrates the impact of the customer charge proposal for the smaller commercial rates:

Table 76

Comparison of Current Rates vs Proposed Rates				
	Current	Proposed	Proposed vs. Current	
	Rate	Rate	Difference	% Chg
Rate 27 - Small TOD General Service				
Customer Charge	$38.50	$55.00	$16.50	42.86%
Demand Charge Greater Than 2 KW	$9.34	$15.35	$6.01	64.35%
Energy Charge On-Peak kWh	$0.19899	$0.16296	($0.03603)	-18.11%
Energy Charge Off-Peak kWh	$0.11493	$0.09941	($0.01552)	-13.50%
Rate 30 - Small General Service				
Customer Charge	$38.50	$55.00	$16.50	42.86%
Demand Charge Greater Than 2 KW	$12.51	$18.52	$6.01	48.04%
Energy Charge First 300 Hours Use	$0.12616	$0.10836	($0.01780)	-14.11%
Energy Charge Over 300 Hours Use	$0.12616	$0.10836	($0.01780)	-14.11%
Rate 40 - Church and School				
Customer Charge	$47.50	$70.00	$22.50	47.37%
Energy Charge All kWh	$0.16473	$0.16980	$0.00507	3.08%

Application, Exhibit EAD-3.

The Authority finds that, similar to the proposed increase to the residential fixed charges, the percentage increase proposed for customer charges for these rates are high, in excess of 40%. As such, the Authority will direct the Company to apply an increase to the fixed charge component for Rates 27, 30 and 40 in one of the following manners: (a) at the individual rate classes distribution percentage increase; or (b) at the overall distribution increase percentage, if higher than (a).

Except as modified above, the Authority finds the Company's rate design proposal acceptable, as it continues the move towards more equitable, cost-based rates while mitigating the impact that such increases have on customers. CL&P appropriately reallocated the revenue responsibility of the rate classes closer to the system average without excessive impacts. The customer and demand charges are fully cost-based,

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Actual bill impact is subject to slight change upon review of the final Rate Plan submitted by the Company.

where possible, and the customer and/or demand charges for the remaining classes move closer to the cost-based rates without excessive impact on customers on either spectrum of usage. The Company will be directed to submit a final rate plan (Rate Plan) that incorporates the following modifications:

1. The Company will file a final-rates COSS reflecting rate year billing determinants, the financial profile approved in this Decision and the then current rates developed in accordance with the Rate Plan approved herein.

2. The Company will include adjustments to Other Revenue for reconnection fee revenue and pole attachment revenue discussed in Section II.J.2. Operating Revenue, when designing rates.

3. The TOD rate structure proposed by the Company as Rate 5 is denied; Rate 7 will continue to be available to either Rate 1 or 5 customers.

4. The approved customer charge for Rates 1 (and associated Rate 7) and 5 are $19.25 and $23.75, respectively.

5. The Company will apply an increase to the fixed charge component for Rates 27, 30 and 40 in one of the following manners: (a) at the individual rate classes distribution percentage increase; or (b) at the overall distribution increase percentage, if higher than (a).

6. The allocation of pro forma revenues to the rate classes will be set in accordance with the directives in Section II.J.4, Revenue Allocation.

7. The Company will apply the increase associated with the adjustment in pole attachment revenue to distribution revenues before designing rates.

8. The Company will apply the net decrease of approximately $489,000 to the 2016 revenue requirement level to offset the revenue allocation to Rate 116 when designing rates, since this rate class received the largest percentage rate increase.

9. The compliance filing for the Rate Plan will consist of the following:

    a. Testimony
    b. Schedule E-1, Scored and Unscored Proposed Tariffs
    c. Schedule E-2.0 Revenue Summary
    d. Schedule E-2.1 Detailed Revenue Summary
    e. Schedule E-2.2 Revenue Calculation
    f. Schedule E-2.3 Typical Bill Comparisons
    g. Schedule E-6.0 COSS
    h. Schedule E-6.0 COSS – Unity
    i. Standard Revenue Proof Exhibits

The distribution rate increase will become effective December 1, 2014; however, new rates will not be implemented until after final approval of the Rate Plan. Since the

Company will be submitting full year rates to be recovered over less than a full year period, it may encounter a shortfall in collecting the approved distribution rate increase. Any such shortfall may be reconciled in the decoupling mechanism approved herein. The Authority notes that the customer bill impact of a portion of the distribution rate increase will be mitigated by a subsequent decrease of the storm related costs which will be removed from the NBFMCC effective January 1, 2015. The Company shall consider the net impacts of the revenue recovery transfer between the NBFMCC and the distribution rates in their revised rate filing and provide this information to the Authority.

6. Pole Attachment Rates

a. Company Proposal

Pursuant to Order No. 1 in the Decision dated September 12, 2013 in Docket No. 11-11-02, Petition of Fiber Technologies Networks, L.L.C. for Authority Investigation of Rental Rates Charged to Telecommunications Providers by Pole Owners (Fibertech Decision), the Company proposed to change its methodology for calculating pole attachment fees under its Community Antenna Television (CATV) pole attachment tariff (CATV Rate), Telecommunications pole attachment tariff (Telecom Rate) and Municipal pole attachment tariff (Municipal Rate). The current pole attachment tariffs provide recurring and non-recurring charges for pole attachments. Recurring charges are typically fees for rental of pole space, and non-recurring fees typically include items such as make-ready costs. Municipal Rate customers are allowed an exemption from pole attachment fees for their first attachment on any pole; therefore, the recurring fees apply predominantly to CATV and Telecom attachers. Pole attachments under all three tariffs are subject to non-recurring fees for make-ready work and other charges for services, as outlined in the tariffs.

To implement Order No. 1 in the Fibertech Decision, the Company proposed adjustments to the formula rate for Telecom attachers consistent with the methodology in the Federal Communications Commission's Report and Order on Reconsideration, In the Matter of Implementation of Section 224 of the Act (WC Docket No. 07-245), and A National Broadband Plan for Our Future (GN Docket No. 09-51), adopted and released April 7, 2011 (Pole Attachment Order). To achieve parity between the Telecom Rate and the CATV Rate, the Company applied factors to the pole attachment Telecom Rate methodology calculations to be consistent with the factors applied in the CATV Rate calculations. Davis PFT, pp. 20-24. The following tables detail CL&P's calculation of the Cable Rate and the Telecom Rate:

Table 77

CATV Formula						
Maximum Rate	=	Space Factor	x	Net Cost of a Bare Pole	x	Carrying Charge Rate
	=	8.11%	x	$643.57	x	31.73%
		Fully Owned		Jointly Owned*		
	=	**$16.56**		**$8.28**		
* Fully Owned Rate / 2						

Table 78

Telecom Formula								
Maximum Rate	=	Space Factor	x	Net Cost of a Bare Pole	x	Carrying Charge Rate	x	Conversion Factor
Maximum Rate (Urban)	=	11.723%	x	$643.57	x	31.73%	x	69.18%
		Fully Owned		Jointly Owned*				
		$16.56		**$8.28**				
Maximum Rate (Non-Urban)	=	17.872%	x	$643.57	x	31.73%	x	45.38%
		Fully Owned		Jointly Owned*				
		$16.56		**$8.28**				
* Fully Owned Rate / 2								

As shown above, CL&P calculated pole attachment rates for the CATV Rate and Telecom Rate of $16.56 for a fully owned pole and $8.28 for a jointly owned pole, respectively. For the CATV Rate, CL&P calculated a space factor of 8.11%, based on the space occupied by one attachment (typically a foot) as a percentage of the total usable space (estimated by CL&P to be 12.33' across its system). CL&P calculated a net cost of a bare pole of $643.57 using a combination of 90% of the embedded cost of a pole of $609.62, and 10% of the marginal (replacement) cost of a pole of $949.14. The Carrying Charge Rate of 31.73% grosses the rate up for elements such as administrative expense, maintenance, depreciation, taxes and rate of return on investment. Application, Exhibit EAD-10.

For the Telecom Rate, CL&P calculated a space factor of 11.723% for poles situated in urban areas and 17.872% for poles situated in non-urban areas, based on the following formula:

$$\text{Space Factor (Urban/Non-Urban)} = \frac{\text{Space Occupied} + \left[\dfrac{2/3 \times \text{Unusable Space}}{\text{No. of Attaching Entities}}\right]}{\text{Pole Height}}$$

CL&P used 27.67' as the unusable space assumption, a pole height assumption of 40' and 3 attaching entities for the urban space factor and 5 attaching entities for the non-urban space factor. CL&P also applied an urban conversion factor of 69.18% and a non-urban conversion factor of 45.38%. Application, Exhibit EAD-10. CL&P stated that applying the new methodology to calculate the Telecom Rate shows that it becomes essentially the same as the CATV Rate, regardless of whether the telecom attachment is classified as "urban" or "non-urban." Davis PFT, pp. 20-24. CL&P's proposed reduction in the Telecom Rate would reduce the amount of pole attachment fee rental revenue received from pole attachments by approximately $164,000 annually. The Company imputed an expected change to the Telecom Rate into its proposed rates.

The Company's proposal converts the stated rate to a formula-based rate, such that the rate and revenue received from pole attachment will vary annually as costs, numbers of attachments and other factors change. The Company also proposed to flow any revenue variation from pole attachment fees that may occur through changes to the rate, as well as changes in numbers of attachers through the Company's decoupling mechanism. The pole attachment rates are billed on a semi-annual basis. Given the proposed December 1, 2014 effective date for implementation of the proposed pole attachment rate methodology, the Company plans to notify customers of the change in rate, and provide prorated bill adjustments for December 2014. On an ongoing basis, rate changes based on the proposed methodology would be calculated, and notice of rate changes would be provided annually for rates in effect on January 1 of each year. Id.

b. NECTA Proposal

The New England Cable and Telecommunications Association, Inc. (NECTA) opposed CL&P's calculation of the CATV Rate and Telecom Rate, indicating that the Company did not follow the Fibertech Decision or the Pole Attachment Order. According to NECTA, CL&P significantly raised the CATV Rate, created its own formula, and lowered the Telecom Rate only enough to meet the inflated CATV Rate. Glist PFT, pp. 5-12. NECTA also stated that CL&P blended parts of a 20-year old rate formula used in a case involving The Southern New England Telephone Company (SNET) with selected elements of the Pole Attachment Order's revised upper bound Telecom formula resulting in an inflated annual pole rental rate. As such, CL&P's pole rate methodology deviates from the Pole Attachment Order by not using the FCC's lower bound Telecom Formula, which excludes capital costs from the cost of providing space, since those costs are recovered through make-ready. The lower bound formula is intended to ensure that pole owners are fully compensated for actual costs associated with pole attachments. Id.

NECTA also argued that CL&P deviated from the Pole Attachment Order methodology as follows:

1. The Pole Attachment Order methodology uses historic (embedded) costs while CL&P uses a combination of historic and reproduction (marginal) costs, which the FCC has expressly rejected;

2. The Pole Attachment Order methodology applies cost allocators of 66% in urban areas and 44% in rural areas while CL&P applies higher cost allocators of 69.18% in urban areas and 45.38% in rural areas; and

3. The Pole Attachment Order methodology allocates pole costs using a presumption of 13.5' of usable space on the pole to derive a space allocation factor while CL&P uses 12.33' without providing credible evidence to rebut the 13.5 feet usable space presumption.

NECTA did not dispute the basic formula used by CL&P used in its calculation, but rather, the assumptions. NECTA outlined the Pole Attachment Order formulas is as follows:

- FCC Pole Attachment Order formula (for Cable) = Net Pole Cost x Carrying Charge Factor x Space Allocation Factor

- FCC Pole Attachment Order formula (for Telecom) = Net Pole Cost x Carrying Charge Factor x Space Allocation Factor x Conversion Factor

Id.

NECTA contended that the average pole height and average amount of usable space on the pole (pole height above ground clearance) has increased. NECTA members, including Cablevision, Charter, Comcast, Cox, and MetroCast, conducted a survey of current pole plant under the direction of NECTA and a statistician, Dr. Charles Cowan, with Analytic Focus (Pole Survey). The Pole Survey used a sample population of approximately 500 poles. The data collected included the pole height and the height of the lowest strand on the pole attached with a through bolt for each sampled pole. The data was then extrapolated back into the total universe of CL&P poles to obtain the average pole height and the average amount of usable space on the pole. According to the study, the average CL&P pole height is 38.57'. Removing 18' clearance and 6' setting depth, the remaining space usable for pole attachments is 14.57', greater than the 13.5' presumption in the Pole Attachment Order and the 12.33' assumption used by CL&P. Id., pp. 5-12; Cowan PFT, pp. 1-5.

In summary, NECTA argued that CL&P calculated a sizable CATV Rate increase and a Telecom Rate that does not meet the Pole Attachment Order methodology. NECTA stated that proper application of the FCC Pole Attachment Order formulas produce solely-owned CATV Rates of $14.33 for cable, and solely-owned Telecom Rates of $14.30 in urban areas, and $14.38 in rural areas. Exhibit PG-2. If any presumptions are changed they should reflect the data collected by NECTA member operators supporting an average pole height of 38.57' and a usable space factor of 14.57'.

c. Position of the Parties

The OCC agreed with NECTA, stating that CL&P has failed to calculate its rates in conformance with the Pole Attachment Order as ordered in the Fibertech Decision. The Company's methodology incorrectly incorporates a rate-setting methodology derived from a PURA order from the 1993 SNET Rate Case. The Fibertech Decision followed the methodology detailed in the Pole Attachment Order, and directed calculations that superseded the SNET 1993 Rate Case Decision. OCC Brief, pp. 133 and 134.

d. Authority Analysis

The Authority agrees that CL&P's proposed pole attachment rates do not conform with the Pole Attachment Order or the Authority's prior directives. In calculating either rate, marginal costs should not be used in calculating the net pole cost. The use of 100% embedded costs is both consistent with the directives of the Pole Attachment Order and other FCC decisions as well as the methodology contemplated by the Authority in the Fibertech Decision. Therefore, the Authority approves the use of the fully embedded net cost of $609.62 in the pole attachment rate calculation. Further, the Authority finds NECTA's proposed average pole height of 37.57', usable space factor of 14.57' and unusable space factor of 24' from the Pole Survey are acceptable for use in calculating rates in this case. The Company will be directed to conduct a usable space survey prior to filing its next rate case. The Authority will use CL&P's proposed conversion factor, adjusted from 31.73% down to 31.54%, to reflect the allowed ROE of 9.02%. Lastly the conversion factors used by CL&P in calculating the Telecom Rate do not conform to the conversion factors outlined in the Pole Attachment Order (66% of the fully allocated costs for urban and 44% for rural) and will be adjusted by the Authority.

Based on the above, the Authority recalculates the CATV and Telecom Rates as shown:

Table 79

CATV Formula						
Maximum Rate	=	Space Factor	x	Net Cost of a Bare Pole	x	Carrying Charge Rate
	=	6.86%	x	$609.62	x	31.54%
		Fully Owned		Jointly Owned*		
	=	**$13.19**		**$6.60**		
* Fully Owned Rate / 2						

Table 80

Telecom Formula								
Maximum Rate	=	Space Factor	x	Net Cost of a Bare Pole	x	Carrying Charge Rate	x	Conversion Factor
Maximum Rate (Urban)	=	10.889%	x	$609.62	x	31.54%	x	66.00%
		Fully Owned		Jointly Owned*				
		$13.82		**$6.91**				
Maximum Rate (Non-Urban)	=	16.420%	x	$609.62	x	31.54%	x	44.00%
		Fully Owned		Jointly Owned*				
		$13.89		**$6.94**				
* Fully Owned Rate / 2								

The Authority approves the Company's proposal to flow variations in pole attachment revenue through the decoupling mechanism, and to provide prorated bill adjustments for December 2014.

7. Unbundling of Street Lighting Rates

a. Existing Street Lighting Rate Design

In the 2009 CL&P Rate Case Decision the Authority approved the unbundling of street lighting rates into their functional components (e.g., Distribution, Transmission and Generation Service). Based on that ruling, the Company proposed an unbundled rate design of street lighting service and set pricing for: (a) the component of service associated with the use of the distribution system that would apply to all street lighting customers, regardless of street light facilities ownership (i.e., the "system" component of rates); and (b) the component of service associated with Company-owned street lighting facilities applicable only to CL&P's full service street lighting customers [e.g., the equipment and operations and maintenance (O&M) components of rates]. The Company stated that a rate structure based on this unbundling is critical to its ability to introduce a Company-owned light-emitting diode (LED) street lighting option that has a cost basis consistent with other traditional street lighting technology options.

CL&P stated that its proposal shows the actual cost of providing these services. It used that data along with other factors to develop a street lighting rate design that better reflects the Company's cost of service. Davis PFT, pp. 14 and 15. The following Table shows the distribution breakout by component:

Table 81

STREET LIGHTING DISTRIBUTION RATE DESIGN					
Distribution Breakout by Component					
Rate Year Ending 2015	Rate 117			Rate 116	
Fixtures	A	46,289		E	141,898
Connected Demand KW	B	5,659		F	22,540
Annual kWh	C	23,425,448		G	92,563,009
Proposed Distribution Revenue	D	$839,496		H	$16,894,406
Distribution by Category					
1) D - System Demand					
Revenue $	I = D * 75%	$629,622		K = J* F* 12* 1000	$2,507,700
Charge Per Watt	J = I / B	**0.00927**		L = K / F	**0.00927**
2) D - System Customer					
Revenue $	M = D * 25%	$209,874		O = N* E* 12* 1000	$643,365
Charge Per Fixture	N = M / A	**$0.38**		P = O / E	**$0.38**
3) D - Operations & Maintenance					
Revenue $				Q = RY COSS O&M	$2,574,000
Charge Per Fixture				R = Q / E	**$1.51**
4) D - Equipment					
Revenue $				S = H- K- O- Q	$11,169,342
Total D		**$839,496**			**$16,894,406**

Exhibit EAD-8, p. 1.

The Company proposed a two-part charge for Partial Street Lighting Service (Rate 117) consisting of customer and demand components that applies to applicable fixtures connected to the CL&P's distribution system. The customer component is a uniform rate per fixture that applies monthly to each fixture connected to the Company's system. The demand component is a uniform rate per watt that applies to the rated wattage of each fixture under either rate schedule. These two charges are combined to form the total charge per fixture each month for the system component of distribution service. The revenue targets for customer and demand were derived by applying a 75% / 25% proportion of demand and customer costs, respectively, to the proposed distribution revenue (D). Accordingly, for each fixture the monthly distribution charge under Rate 117 would be $0.38 plus the product of $.00927/watt and the wattage of that fixture. These would be the only distribution charges for service under Rate 117, and also become the system-related distribution charges for Street and Security Lighting (Rate 116). CL&P contended that the proposed rate design appropriately charges all street lighting fixtures the same formula distribution rate for the use of the system, regardless of wattage and regardless of equipment ownership.

For Rate 116, additional equipment and O&M charges apply. The street lighting O&M rate is an average monthly rate that applies uniformly to all Rate 116 fixtures. This rate, which equals $1.51 per fixture, has been derived directly from street lighting O&M expenses of the COSS shown on page 2 of Exhibit EAD-8. The monthly equipment charge was developed for each specific type of equipment utilized by customers taking service under Rate 116. CL&P developed these charges by calculating the total installed cost of each type of equipment and developing a monthly rate by multiplying a street lighting carrying charge by the installed cost of each type of street lighting equipment. The Company proportionally adjusted the calculated equipment charges by a factor of 1.054 (the ratio of the $11.2 million equipment revenue requirement to the $10.6 million calculated equipment revenue) to derive proposed equipment prices. Davis PFT, pp. 13-19; Exhibit EAD-8, p. 3.

b. New Street Lighting Options

The Company proposed to introduce several new street and highway lighting options that utilize LED technology. The unbundling and development of rates for the system, equipment and O&M components of street lighting service discussed above provide a structure upon which the Company has been able to develop LED rates. The same methodologies for determining the system, equipment and O&M rates for other street lighting service offerings has been applied in developing proposed LED street lighting distribution rates. Davis PFT, pp. 13-19; Exhibit EAD-8.

The Authority accepts CL&P's proposed unbundled rate design methodology for Rates 116 and 117. The proposed rate design effectively carves out the equipment costs from the general distribution system costs and allocates the equipment costs to customers in a manner that is more cost-based than the previously bundled rates. The Company will be directed to adjust the proposed rates to reflect the new revenue targets shown in Section II.J.4, Revenue Allocation.

8. Tariff Changes

a. Company Proposals

The Company proposed to update certain provisions in its rate schedules and terms and conditions (T&Cs) for service and to update charges for a number of services provided under the T&Cs. The Company also proposed to withdraw its surge protection tariff as previously approved by the Authority; proposed tariff language to implement the unbundling of street lighting offerings, as discussed in Section II.J.7, Unbundling of Street Lighting Rates; and proposed a new TOD rate for residential heating customers on Rate 5.

i. Terms and Conditions for Electric Suppliers

The Company's proposed amendments to the T&Cs for Electric Suppliers included several proposed new definitions and clarifying provisions associated with changes in market-related services, obligations and practices (e.g., supplier switching rules), and elimination and proposed changes to fee structures for data and information services. Davis PFT, pp. 24 and 25, Exhibit EAD-11.

ii. Terms and Conditions for Delivery Service

The Company's proposed amendments to the T&C's for Delivery Service included clarifying changes to definitional terms and labeling, and several new provisions including unauthorized use and meter diversion. These T&C amendments included a proposed new meter diversion fee, proposed changes to the reconnection fee structure and rates, and proposed, restructured extended metering options. The proposed rates for these services have been developed based on the cost of providing service under these options. Davis PFT, pp. 24 and 25, Exhibit EAD-11.

iii. Withdrawal of Surge Protection Tariff

The Company requested approval to withdraw its surge protection tariff, pursuant to a previous letter order ruling by the Authority approving the CL&P's request to discontinue this program.[51] Also, a new Metering Communications Equipment provision is proposed to replace the Telemetering provision (or to be added where such provision is not currently stated) for any schedule that has meter communications requirements associated with electric service meters. The Company also proposed clarifying language regarding the availability and applicability provisions associated with small commercial rates (Rates 27, 30, 35 and 37), and with regard to the billing of certain charges under the Company's net metering tariffs. Davis PFT, pp. 24 and 25, Exhibit EAD-11.

iv. Residential Heating Time-of-day Rate

Currently, CL&P offers a TOD rate option, Rate 7, for residential non-heating customers. Rate 7 was designed based on the service characteristics of the non-heating residential class, Rate 1, and on methodologies and guidelines developed and approved by the Authority that resulted in time-differentiated generation service rates and an overall rate design conducive to the migration of Rate 1 customers to Rate 7 TOD service. Because residential heating customers do not have a comparable TOD option, the Company developed a new TOD rate, Rate 6, based on the specific service characteristics of Rate 5 and application of the same methodologies and guidelines used in developing Rate 7. Davis PFT, pp. 19 and 20.

The general availability, applicability and other provisions of Rate 6 are identical to those of Rate 5, with the exception that Rate 6 is open to new customers. As in the Rate 7 rate design, the non-TOD rate components of Rate 6, including the customer charge and per kWh charges, are the same as those for Rate 5. The generation service charge however, has been developed on a TOD basis using the same differential between peak and off-peak rates as used in designing Rate 7 pricing. This differential has been applied on a revenue neutral basis to develop the TOD equivalent of the Rate 5 generation service charge and thereby provide a TOD rate option specifically for Rate 5 customers. Id., Exhibits EAD-11 and EAD-12.

b. Position of the Parties

The BETP generally supported time-of-use rates; however, it suggests that CL&P educate customers on the benefits of time-of-use rates and improve the structure of its existing time-of-use rates rather than add another new residential rate. The BETP also suggested that CL&P redesign its Residential Time-of-Use Rate 7 and focus on

[51] See, March 20, 2014 letter order ruling on Motion No. 54 in Docket No. 09-12-05.

educating customers on the value of time-of-use rates rather than create a new and unnecessary time-of-use rate. It is unclear why CL&P is proposing a new time-of-use rate option other than to have a rate that directly corresponds to Rate 5 residential heating. The rate design and resulting bills for Rate 6 are very similar to those on Rate 7, which is already available to Rate 5 customers. Rate 7 however, has not been successful in attracting customers from Rate 1 or Rate 5. Less than 500 customers receive service on Rate 7 compared to over 1.1 million customers on Rate 1 and Rate 5. The BETP commented that CL&P has done little to educate customers and promote time-of-use rates in the past and does not have a plan to do so in the future. BETP Brief, pp. 14 and 15.

c. Authority Analysis

The Authority denies the Company's proposed implementation of the proposed Rate 6 as a TOD companion tariff to Rate 5. Rate 5 is a legacy tariff and new customers are no longer allowed to take service under that rate. It seems counterintuitive to allow new customers to take service under a companion tariff to Rate 5. However, the existing TOD Rate 7 should continue to be made available to Rate 5 as well as Rate 1 customers. Since both the customer and the volumetric delivery charges under Rate 7 will be lower than Rate 5, customers will still realize a benefit on the distribution portion of their bill as well as the differential between peak and off-peak rates in the generation services charge. It remains uncertain as to how much of an incentive will be necessary to drive significant migrations to TOD rates for any type residential customer. This is evident by the lack of participation in Rate 7, and the anticipated low migration rates the Company expects for Rate 6. CL&P Response to Interrogatory RA-22. Further, it is unclear whether a similar pricing mechanism would be the right fit for a heating customer's service characteristics. The Authority welcomes more discussion on this matter and how the current residential TOD tariffs could be redesigned to stimulate more customer participation.

The Authority finds it appropriate, given the increase to distribution rates herein, to require that CL&P increase the charge for reconnection at the meter from $35 to $42, instead of the Company's proposal to lower that charge to $31. This rate has not changed in many years, despite increases to general rates.

The Authority accepts the Company's remaining proposed tariff changes subject to rate amendments pending Authority approval of final rates as directed in Section II.J.5, Rate Design. Regarding the availability sections of Rates 27, 30, 35 and 37, the Authority approves the Company's proposed minimum demand requirement of 200 KW under which customers are not eligible to return to Rate 30 or Rate 35.[52] The Authority approves the proposed revisions to Rates 116 and 117 with the associated charges subject to change pending the reallocation and rate design of the approved revenue requirements herein.

[52] The Authority previously ordered that it be lowered to 100 kW in a three-phase implementation process in the 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. By Decision dated May 10, 2010 in that Docket, the Authority delayed the implementation of the final phase of Order No. 7.

K. NEW BUSINESS POLICIES

CL&P's New Business Policies (NBP) establish standardized costs and methodologies for developing work estimates and for billing customers those costs that are customer-specific which are not recovered in rates. CL&P submitted revisions to its NBP in this proceeding. Bowes PFT, Exhibit KBB-5.

CL&P's NBP revisions primarily reflect organizational changes that have taken place since the Company's last revisions in 2011. The revisions also update certain prices to current costs, and update metering technology and requirements to current standards, which have evolved over time, particularly with regard to distributed generation interconnections and communication technology. No party or intervenor opposed the Company's NBP revisions.

The Authority finds that the NBP revisions are reasonable and appropriate. The Authority therefore approves the revisions to the NBPs.

L. CUSTOMER SERVICE ISSUES

1. Customer Notifications and Collections

CL&P's standard bill form, termination notice and customer rights notice were reviewed and found to be in compliance with applicable regulations. Application, Schedule H-2.0, Exhibits A and B; Response to Interrogatory CA-7. CL&P's Terms and Conditions for Delivery Service were also reviewed and found to be in compliance with applicable regulations. Application, Schedule H-2.0, Exhibit E, Schedule E-1.0 and E-1.1; Response to Interrogatory CA-19.

The Company implemented a strategy in 2010, to more effectively manage and pursue collections on inactive customer accounts, and modified the plan for efficiency in the following three years. CL&P then summarized the results of its changes in workflow timing for collections efforts in relation to final bills, and indicated a noticeable increase in its collection of outstanding revenues. Response to Interrogatory CA-5. The Company measures its "net back," which is the total collections made on its behalf, minus the commissions that CL&P pays to the collections agency. The Company's Net Recovery percentage increased from 0% to 7.1% between 2010 and June 2014. Id.; Tr. 8/27/14, pp. 61 and 62. The total number of accounts in arrears increased 12% from 114,808 in June 2011 to 128,595 in June 2014. However, the total amount of arrearages increased only 1.3%, from $76.5 million to $77.5 million, during the same period. Response to Interrogatory CA-21.

2. Policy and Procedures for Estimated Billing

CL&P provided its policy and procedures for generating an estimated bill. CL&P's billing system produces an estimated bill based upon historical usage in the comparable month in the prior year. The Company continues to follow the automated notification process to inform customers of options to avoid an estimated bill as outlined in Order No. 20 in the 2009 CL&P Rate Case Decision. Response to Interrogatory CA-1.

CL&P issues estimated bills infrequently. The table below shows the percentage of estimated bills issued over time periods ranging from one month to 12 or more months:

Table 82

Year	1 Month	2-3 Months	4-6 Months	7-11 Months	12+ Months
2014 Y-T-D	1.487%	0.263%	0.073%	0.003%	0.000%
2013	2.760%	0.518%	0.127%	0.041%	0.001%
2012	1.275%	0.542%	0.138%	0.012%	0.000%
2011	3.298%	0.703%	0.201%	0.017%	0.000%

Response to Interrogatory CA-13.

The Authority finds the extremely low percentage of estimated bills issued by the Company supports CL&P's current estimated billing policy and procedures. The Company's estimated billing procedures have been reviewed and found to be in compliance with applicable regulations. CL&P's bill form and associated customer notices were also reviewed and found compliant. Application, Exhibit H-2.0, Exhibit D.

3. Customer Security Deposits

The Authority has reviewed CL&P's current customer security deposits policies and procedures and found them to be in compliance with Conn. Agencies Regs. §16-11-105 and §16-262-1. Application, Schedule H-2.0 Exhibit F, Customer Service Policies, No. C150.1 and No. C350.1; Response to Interrogatory CA-18. The Company provides policy and procedures in writing to those customers that are required to pay a security deposit, and stated that there are other means by which customers are informed of security deposit requirements. For example, termination notices inform the customer that a security deposit may be required before service can be restored, and CL&P's Customer Service Representatives remind customers that a deposit is required when reinstating service. Finally, new commercial accounts receive information in the mail regarding security deposit requirements and how they are calculated. Response to Interrogatory CA-18.

4. Energy Audit Service Appointments

In October 2012, CL&P informed the Authority of its intent to discontinue the practice of on-site energy audit service appointments at a customer's location by Energy Service Representatives. Docket No. 09-12-05, Order No. 19 compliance filing dated October 3, 2012. The new customer service practice is to guide customers to more comprehensive energy savings programs such as the Connecticut Energy Efficiency Fund's Home Energy Solutions. The Company maintains that these programs are a cost-effective way to provide customers with maximum energy and dollar savings. Id. After completing its own review of the Company's policy change as described above, the Authority approved the change in November 2012. PURA Response to Docket No. 09-12-05, Order No. 19 compliance filing dated November 2, 2012.

5. NUStart Program

CL&P changed its NUStart program in 2013, shortening it from a three-year program to a one-year program, because customers were routinely failing to maintain required budget payments over a 36-month period, and thus placed back in the service disconnection stream. By converting NUStart to a one-year program, an increased amount of forgiveness dollars is applied to NUStart balances, which helps reduce arrearages at a quicker pace. From 2010 to 2012, only 1,543 customers completed the NUStart program. After the program change was made in 2013, approximately 6,000 customers successfully completed the program. In the first six months of 2014, 2,347 customers successfully completed the NUStart program. NUStart program changes have dramatically increased participants' success. Response to Interrogatory CA-15.

6. Customer Call Center

CL&P maintains a Customer Service Center to address customer complaints and inquiries. Statistics below, submitted by CL&P for calendar years 2012 through 2014, depict the call center's monthly performance:

Table 83

2012	ASA[53]	ACR[54]	2013	ASA	ACR	2014	ASA	ACR
January	31.5	2.6%	January	15.9	1.3%	January	60.2	5.3%
February	35.3	2.8%	February	20.7	1.8%	February	38.7	3.4%
March	29.9	2.7%	March	14.4	1.1%	March	20.4	1.9%
April	51.4	3.9%	April	23.0	1.2%	April	6.1	1.1%
May	25.5	2.2%	May	24.7	1.9%	May	12.9	1.5%
June	10.8	1.3%	June	25.2	2.5%	June	9.6	1.4%
July	12.8	1.8%	July	27.5	2.4%	July[55]	12.0	1.8%
August	10.7	1.4%	August	26.0	2.2%	-------	------	-------
September	18.8	1.8%	September	27.3	2.7%	-------	------	-------
October	13.9	1.4%	October	7.4	1.1%	-------	------	-------
November	14.2	1.5%	November	15.7	1.9%	-------	------	-------
December	17.3	1.8%	December	8.7	1.4%	-------	------	-------

Response to Interrogatory CA-2.

Currently, there are no specific standards or benchmarks for electric distribution company call center metrics set forth in Connecticut's state statutes or regulations. The Authority finds CL&P's call center performance statistics to be acceptable as filed, based upon its experience in reviewing other regulated utilities call center statistics. Response to Interrogatory CA-2.

CL&P participates in monthly meetings with the Authority's Consumer Affairs Unit as a means to improve upon the level of service provided to customers. These monthly meetings were established in the 2009 CL&P Rate Case Decision, Order No. 30. All parties agree that these meetings have been helpful in handling customer service matters and the parties mutually agree it will be beneficial to continue meeting each month.

7. Conclusion

Overall, the Authority finds CL&P's customer service policies and procedures to be in compliance with applicable statutes and regulations.

III. FINDINGS OF FACT

1. The ADIT for the Test Year ending December 31, 2013 is $655.417 million.

2. The plant related non-FAS 109 ADITs were $461.429 million, $553.453 million, $567.297 million, $674.02 million, and $658.815 million for calendar years ending December 31 in 2009, 2010, 2011, 2012 and 2013, respectively.

53 Average Speed of Answer, in seconds.
54 Abandoned Call Rate.
55 Through July 13, 2014.

3. The deferred tax liability created by the permanent RTD regulations will reverse over the same time period as the related assets capitalized in accounting books are depreciated.

4. RTD treatment is the same as that of other normalized deductions for tax and regulatory purposes.

5. CL&P included normalized ADITs of $40.85 million in 2014 and in 2015 for RTD.

6. The 2014 and 2015 levels of ADITs are based on RTD allowances of $100 million in each year.

7. CL&P did not adopt the RTD temporary regulations.

8. CL&P will adopt the final RTD regulations and include benefit associated with RTD deductions for 2012 and 2013 in its 2014 tax returns.

9. There are additional look-back periods for which costs incurred for repair and maintenance of tangible property can be deducted in the 2014 tax return with the adoption of the final RTD regulations.

10. CL&P failed to incorporate additional deferred tax benefits for the RTD look-back periods, which included 2012 and 2013, in its estimated deferred taxes for 2014.

11. CL&P will be included in that cumulative adjustment in its 2014 tax return, amounts which would have been deducted in 2012 and 2013.

12. The Company will record additional normalization deferred tax liabilities for the 2012 and 2013 RTD allowances in its books.

13. The Company only included the deferred taxes associated with RTD allowances in 2014 and 2015 in this proceeding.

14. The Company reduced the ADITs balance Account 28200 by $124,742,248 in August 2013.

15. The $124,742,248 reduction represents a subsequent true-up of estimates made during 2012 based on adjustment in its 2012 tax return.

16. A shorter retirement schedule increases the deduction for depreciation expense for a particular period.

17. Businesses may automatically change from one permissible method of computing depreciation expense for tax purposes to another permissible method by filing Form 3115.

18. Recent tax law changes allow corporations special tax deductions, above the normal MACRS amounts.

19. Account 282 is debited and Account 411 is credited with an amount by which income tax is greater due to tax/book differences from prior years.

20. The net changes to the balances in Account 28200 are $95.888 million in 2011, $100.262 million in 2012 and ($42.293) million in 2013.

21. The annual accretions to the ADITs balances in Account 28200, exclusive of true-up adjustments, are $95.888 million in 2011, $101.330 million in 2012 and $82.449 in 2013.

22. The total federal depreciation deductions are $541,275,640 in 2011 and $586,677,407 in 2012.

23. The distribution portions of total federal tax depreciation deductions are $359,956,682 in 2011 and $384,142,472 in 2012.

24. No adjustments were made to the balance in Account 28200 in August 2011 and a reduction of $1.1 million in August 2012.

25. On August 1, 2013, the Company submitted to the Authority a compliance filing that included a Form 3115 filed with the IRS.

26. In the Form 3115 filed on July 10, 2013, CL&P requested an automatic change of its method for accounting for certain retirement costs.

27. The amount changed from NOL was $19.939 million in 2011 to $118.004 million in 2012.

28. The total system resiliency plant addition in 2013 was $25.554 million.

29. The book depreciation related to total system resiliency plant addition in 2013 was $198,000.

30. The ADIT associated with the total 2013 system resiliency plant addition was $252,000.

31. CL&P used a stratified random sample of its retail accounts and calculated that it took an average of 40.95 days for CL&P to receive its revenues once service has been rendered based on data through December 31, 2013.

32. Included in this average revenue lag of 40.95 days is a service lag (time between service being provided and the reading of the meter) of roughly 15 to 16 days, a billing lag (time between the reading of the meter and sending out the bill) of two to three days and a payment lag (time between the bill being sent out and the payment being received by the Company) of approximately 23 days (41 days minus 15 days minus 3 days).

33. The Company calculated a cash working capital requirement of $17,230,000 based on a net lag of approximately 3.20 days for the Rate Year.

34. The OCC argued that non-cash expenses should not be part of the lead/lag study because they do not involve an outlay of cash and are excluded by some regulatory jurisdictions in the determination of a working capital allowance.

35. If there is a lag between a reduction in rate base resulting from an expense and the receipt of revenues recovering the expense, a carrying cost is incurred by the Company for the time of the lag.

36. The lead/lag study proposed by the Company assumes and/or calculates that depreciation expense (and expense related to amortization and deferred taxes) results in a reduction to rate base after 15 days on average and that funds for this expense are received 25.95 days later.

37. A service lag is appropriate for revenues associated with most expense categories, but not appropriate for revenues associated with costs recovered through adjustment clauses that use billed revenues.

38. Based on billing cycles of 27 to 33 days and 12 months in a year, a reasonable estimate of the service lag would be 15.21 days.

39. The Company identified three of its adjustment clauses as using billed revenues to recover costs; the CTA, the SBC and the NBFMCC. These clauses recover $30,860,000, $41,418,000 and $189,702,000 in Rate Year costs, respectively.

40. The expense and income levels used to calculate the working capital needs of the Company reflect the expense and income adjustments made by this Decision.

41. The Traditional Capital Program consists of expenditures for programs that address routine infrastructure issues such as those necessary to supply new customer loads, meet peak loads, meet basic business requirements, meet regulatory commitments, and reliability related projects.

42. The Pre-Approved Resiliency Plan consists of system resiliency expenditures for programs that were approved in the Resiliency Decision.

43. The New System Resiliency Programs are for system resiliency measures that were not approved in the Resiliency Decision.

44. CL&P proposed to spend $257 million on its Traditional Capital Program in the Rate Year.

45. The Authority previously examined the issue of plant in service forecasting in its Decision in Docket No. 05-07-04.

46. Total CL&P capital spending over the years 2010-2012 was $958.8 million, which was within 0.2% of its forecast.

47. CL&P planned to spend $44 million on its New Resiliency Programs in 2015.

48. In the 2013 Study, CL&P used a depreciation system composed of the straight line method, ASL procedure, and remaining life technique.

49. CL&P last filed a Depreciation Study based on plant as of December 31, 2008.

50. The Company originally requested a Rate Year payroll expense of $135.881 million.

51. The Company revised the requested Rate Year payroll expense to $135.198 million.

52. The Company's requested level of FTE positions is 4,435.8 for the Rate Year.

53. Since the merger in April 2012, staffing levels have been reduced.

54. As of August 31, 2014, the Company had 4,235.8 FTEs.

55. From December 31, 2013 through August 31, 2014, 201 positions became vacant due to attrition.

56. Of the 201 open positions, CL&P is actively seeking to fill 101..

57. Of the remaining 100 positions, 68 are for CL&P and 32 are for NUSCO.

58. As of September 5, 2014, the Company had 82 of the 101 positions still active and open.

59. The remaining 100 positions are at various stages of review in the Company's Human Resources organization and within the businesses.

60. The Company used a benefits loader of 46.2% and a payroll taxes loader of 8.5%.

61. CL&P has a defined benefit pension plan that covers the majority of its existing employees.

62. In 2006, CL&P closed entry to its defined pension benefit plan to newly hired non-bargaining employees.

63. On January 1, 2006, the Company introduced a new enhanced 401(k) based benefit called the K-Vantage Program for all new non-union hires and allowed existing employees to opt out with their pension frozen into the new benefit program.

64. All new employees participate in the K-Vantage benefit instead of a defined benefit plan.

65. The Company offers retiree health care benefits for all retired employees.

66. The pension expense was calculated on the basis of the accounting rules set forth in ASC 715-30.

67. Pension service cost is the increase in projected benefit obligation due to the accrual of benefits that occurred in the current period.

68. Pension interest cost reflects the growth in present value of projected accrued benefit obligations as they come one period closer to payment.

69. CL&P's pension Test Year expense was $47,213,000.

70. For pension expense, CL&P requested $27,736,000 in the pro forma rate year of 2015.

71. The OPEB expense is calculated on the basis of the accounting rules set forth in ASC 715-60.

72. The health care cost trend rate represents the expected annual rates of change in the cost of health care benefits currently provided by the post-retirement health care benefit plan.

73. CL&P's OPEB Test Year expense was $7,771,000.

74. For OPEB expense, CL&P requested $4,061,000 in the Rate Year.

75. CL&P capped health care subsidies and changed plan designs for both pre-65 retirees and post-65 Medicare eligible retirees.

76. The portion of post-retirement health care expense associated with capped benefits has grown to 85% as of December 31, 2013.

77. CL&P transitioned pre-65 retirees to the same medical designs offered to active employees in 2013.

78. In 2013, CL&P introduced a Medicare Part D employer group waiver plan through its pharmacy benefits manager.

79. CL&P retiree participation in the employer group waiver plan provides lower cost as a result of offsetting payments from Medicare in the form of Part D direct subsidy payments, low income subsidies, pharmacy manufacturer reimbursements, and catastrophic reinsurance payments.

80. In 2014, the Company updated the plan design for Medicare eligible retirees which eliminated non-Medicare coverage and applies the full Medicare Part B deductible on all participants.

81. In 2007, CL&P implemented a Med-Vantage that supplements benefits offered to employees in K-Vantage.

82. The key actuarial assumptions used in determining the Company's pension and OPEB expense are: 1) discount rate, 2) expected return on assets, 3) average wage increase, and 4) health care cost trend rate.

83. The discount rate is used to evaluate the present value of the plan liabilities.

84. The higher the discount rate, the lower the present value resulting in lower pension and OPEB expense.

85. Expected return on plan assets is an assumption, not an actual return, and is a product of plan investment mix and the expected earnings on such mix.

86. The higher the return on plan asset assumption, the more the plan assumes it can earn resulting in lower pension and OPEB expense.

87. The average wage increase is the assumed increase in annual wages for all employees in the plan.

88. The higher the average wage increase assumption, the higher the pension expense.

89. The health care cost trend rate is comprised of an initial and ultimate cost trend rates which is an estimate of future health care costs.

90. The higher the health care cost trend rates, the higher the OPEB costs.

91. The health care cost trend rate applies only to the OPEB Plan.

92. The SEC requires the use of high quality bond yields to calculate the discount rate.

93. CL&P used a discount rate of 4.26% as an input to calculate pension expense and a discount rate of 4.07% to calculate OPEB expense.

94. CL&P used input from actuaries, consultants, and economists to develop the expected long-term rate of return assumption of 8.25%, for both the pension and OPEB plans.

95. Data inputs for the expected long-term rate of return assumption are derived from long-term inflation and growth statistics for the economy.

96. The Company used an average wage increase assumption of 3.50% in its actuarial calculations.

97. There are two assumptions composing the healthcare cost trend rate: the initial assumption and the ultimate assumption.

98. The initial healthcare cost trend rate assumption reflects expectations of health care cost increases for retirees in the near term. It is based on a number of factors including publically available general industry surveys, actual experience of the Company's retiree population, and experience of other large clients with post-retirement health care plans.

99. The ultimate healthcare cost trend rate assumption is developed from a building block methodology. It is established to reflect improvement in technology and additional utilization.

100. The assumptions used in the valuation of the initial and ultimate health care trend rates are evaluated against those used by other general and utilities industry companies to ensure comparability.

101. CL&P used an initial health care cost trend rate of 6.75% with an ultimate rate of 4.50% for the calculation of the OPEB expense.

102. A 401(k) plan is a qualified retirement plan under the Internal Revenue Code that allows employees to save a portion of their salary for retirement on a pre-tax basis.

103. In a 401(k) employers match a portion of each employee's contribution with the employee choosing the investment options for the contributions.

104. By the end of the Test Year of 2013, approximately 30% of CL&P and NUSCO employees were participating in K-Vantage as compared to less than 20% in 2009.

105. A SERP is a non-qualified plan that provides executives with a supplemental retirement benefit in addition to the benefit provided under the qualified plan.

106. There are 34 current employees eligible for SERP benefits when they retire.

107. There are 51 retired employees and/or spouses currently collecting SERP benefits.

108. There will be no new participants in the SERP because CL&P no longer offers a defined benefit pension plan to new employees.

109. CL&P's SERP complies with section 409A of the IRS Code.

110. CL&P's Test Year SERP expense ending December 31, 2013, was $1,680,000.

111. For SERP expense, CL&P requested $2,039,000 million in the pro forma rate year of 2015.

112. The Non-SERP account is used to record expenses related to specially negotiated post-employment benefits, including pension enhancements not covered by the NUSCO Retirement Plan or the SERP.

113. Non-SERP enhancements are normally provided in the hiring agreements to make up for benefits lost at previous employers by some mid-career hires or as part of a separation agreement with NU.

114. CL&P provided a Non-SERP benefit to one employee that was hired after January 1, 2006, but excluded that expense in the rate year.

115. The Authority allowed the Non-SERP benefit in the 2007 Rate Case.

116. Allocations from NUSCO are made through direct charges to the operating company that benefitted from the charge whenever possible.

117. NNECO was the agent for Northeast Utilities system companies and other New England utilities in operating and maintaining the Millstone Nuclear Generation facilities.

118. In the 2009 CL&P Rate Case, CL&P was allowed recovery of 81% of NNECO pension costs in rates.

119. CL&P's pension expense projections included costs being allocated to CL&P distribution operations from NNECO.

120. CL&P capitalized a portion of its pensions and OPEB expenses into rate base.

121. When employees are doing capital work, a portion of their benefits and pension costs are capitalized with their direct labor costs.

122. The amount of pension expense that is capitalized is based on the payroll that is capitalized.

123. The actual capitalization amounts recorded on the Company's books reflect an allocation of employee benefits, payroll taxes and insurance to expense and capital consistent with how payroll was distributed and recorded in the Test Year.

124. CL&P requested $310,000 for consulting/actuarial fees on Schedule C-3.27 for both the Test Year and the Rate Year.

125. CL&P consultant and actuarial fees have been trending downward since 2010.

126. The Company requested $1.5 million for rate case expense associated with this proceeding.

127. The Company proposed the rate case expense be amortized over seven years.

128. The proposed $1.5 million rate case expense includes $100,000 for an ROE witness; $350,000 for a depreciation witness; $500,000 for legal expenses; $300,000 for OCC consultants; $100,000 for other external costs and $150,000 for incremental costs.

129. The projected Rate Year rate case expense is 611% higher than the previous rate case.

130. The Company recovered the 2009 CL&P Rate Case expense in one year.

131. The Authority typically allows amortization periods of three to five years.

132. Residual O&M expense represents the portion of Test Year expenses that CL&P specifically did not analyze based on the size of the dollar amounts involved.

133. CL&P revised its residual O&M expense request due to an accounting error.

134. For the Test Year ended December 31, 2013, CL&P subtracted total expenses excluding residual of $379,216,000 from total Test Year O&M expense of $381,729,000 for a Test Year residual O&M Expense of $2,513,000.

135. A Test Year pro forma adjustment of $2,122,000 and a Rate Year pro forma expense of $4,635,000 were made.

136. Test Year total operating expenses were charged to over 500 accounts and sub-accounts.

137. For CL&P Distribution and NUSCO, costs allocated to CL&P Distribution Test Year expenses were broken down into CCC levels by direct costs.

138. In April 2013, The State of Connecticut reimbursed CL&P in the amount of $2,553,000 for an overpayment of the State Economic Recovery Reduction Bonds.

139. CL&P made an accounting adjustment correction of $1,442,000 for storm costs.

140. In December 2013, CL&P Distribution Company recorded $106,000 in payments in error as a residual O&M expense which was corrected in January 2014.

141. The $4,635,000 million rate year request of residual O&M expense does not reflect an inflation factor.

142. CL&P removed Account No. 90500, Miscellaneous Customer Account Expense, of $143,167 from residual O&M expenses.

143. CL&P removed Account No. 921105, Office Expense Building, of $63,819 from residual O&M expenses.

144. The Company reported that $106,000 was incorrectly charged to CL&P for the low income special needs program payable to the Boathouse Group in December 2013.

145. CL&P reflected an $119,000 decrease in officer's expense from its residual O&M request.

146. CL&P reflected a $207,000 decrease in miscellaneous costs from its residual O&M request.

147. The Company included $583,000 in its Application for BOD expense.

148. The main objective of the BOD is to protect the interest of the Company's shareholders.

149. Ratepayers may indirectly benefit from the activities of the BOD.

150. In the past, the Authority has allowed 25% of BOD expense be funded by ratepayers.

151. CL&P requested $467,000 DOL insurance.

152. Shareholders are the primary beneficiaries of DOL insurance.

153. In the past, the Authority has allowed 25% of DOL insurance expense be funded by ratepayers.

154. The Company originally requested an increase of $4.50 million for healthcare benefits expense but revised that amount to $4.21 million.

155. The total requested for healthcare benefits expense was $22.0 million.

156. The increase in the healthcare benefits expense is necessary to recover the normal escalation of healthcare costs.

157. The Company stated that the increase was determined in collaboration with Strategic Benefit Advisors, CIGNA healthcare and other trend survey data.

158. The Company used a self-funded program design.

159. CL&P's Test Year non-executive incentive compensation was $7.8 million.

160. The total non-executive incentive compensation requested for the Rate Year is $10.38 million.

161. The Company excluded executive incentive compensation expense of $8.7 million from the Application.

162. CL&P's variable pay program is designed to drive performance improvements and operational excellence.

163. The importance of incentivizing employees is to achieve higher standards of customer service and other goals.

164. Incentive compensation expenses should not be borne solely by the ratepayers.

165. The Authority has allowed some level of employee incentive compensation in previous decisions.

166. The Company included $4,765,000 of public liability expense for the Rate Year.

167. The Test Year liability expense was $1,955,000.

168. The initial proposed expense is an increase of $2,810,000 over the Test Year.

169. CL&P revised its public liability expense downward to $3,972,438 based on an updated actuarial report.

170. The total rent expense for the Test Year was $9.527 million.

171. The total proforma rent expense adjustment of $802,000 consisted of reductions of $680,000 to internal and $122,000 for external rent expenses.

172. The $680,000 reduction to the internal rent expense removes $623,000 associated with 56 Prospect Street in Hartford and $57,000 associated with the closure of facilities through consolidation.

173. CL&P included $203,269 for the NSTAR Corporate office in Boston, Massachusetts in the total external rent expense proposed for the Rate Year.

174. RRR manages NU's facilities and its internal rent expense that consists of interest, depreciation, property tax and equity return expenses.

175. The total internal rent expenses are allocated based on Test Year budgeted total payroll costs for NUSCO's employees.

176. CAU 99 allocation rates are used for directly and allocated RRR's rent expense.

177. CL&P allocated $4,047,520 out of the total rent expense of $8,578,534 for the Berlin Campus.

178. CL&P allocated $710,109 out of the total rent expense of $1,290,971 for the 3333 Berlin Turnpike Buildings.

179. CL&P allocated $1,651,607 out of the total rent expense of $3,818,745 for the Windsor CS facilities.

180. The first stage in the allocation internal rent expenses is based on the total square footages occupied by the NU operating companies and by NUSCO. The second stage involves the apportionment of the total operating companies' and NUSCO portions of the total rent amounts to the operating companies.

181. The allocation factors for CCC 048, 06F and 121 are used to allocate the total operating companies' portions of the total rent expenses for the RRR facilities to the operating companies.

182. The CCC 141 of 43.25% was used to allocate NUSCO's portion of total rent expense for the RRR facilities to CL&P distribution.

183. The ROE used to calculate the equity return costs included in the total rent expense for each of the RRR facilities is 9.92%.

184. The total rent expense for the Berlin Campus of $8,578,534 included total equity cost of $3,996,782.

185. The total rent expense for the 3333 Berlin Turnpike Buildings of $1,290,971 included total equity cost of $602,726.

186. The total rent expense for the Windsor CS of $3,818,745 included total equity costs of $1,800,458.

187. NSTAR shared service company merged into NUSCO effective January 1, 2014.

188. Approximately $59.874 million was billed to NSTAR Gas and Electric and $252.358 million was billed to CL&P by NUSCO.

189. Costs for facilities floor space should be allocated based on the projected square footage occupied.

190. In the 2009 CL&P Rate Case Decision, the Company was directed to be charged rent expense by NUSCO based on the square footage directly charged or allocated to CL&P.

191. The 9C allocator is based on NUSCO's employee labor costs and is used to allocate internal rent expense to CL&P.

192. The CCC 1NR allocator mirrors 9C, is based on NUSCO budgeted labor costs and does not allocate costs to the NSTAR companies.

193. For allocating NUSCO's costs to operating affiliates, the CCC 048 factors are based on square footage of the Berlin Campus using the C7 allocators.

194. Under the C7 allocation, the total CL&P distribution allocation factor is 32.94% and the NSTAR factor is 32.53%.

195. The facilities management costs for CCC 136 are allocated using the C7 Rate Code factors.

196. The C7 allocators are based on the new NUSCO's budgeted labor costs for both NU and NSTAR affiliates.

197. CL&P distribution has an allocation factor of 26.95% under the C7 formula.

198. The C7 allocator mirrors the 9C allocator, except that it is based on the new NUSCO's budgeted labor costs, not solely on the old NUSCO costs.

199. The 9C allocators are for the Test Year and rate C7 factors are for Rate Year.

200. The NUSCO Capital Funding expense funds certain capital investment that support shared services and the expense is shared among all NU subsidiaries using the shared capital investments.

201. The NUSCO Capital Funding expense for the Test Year was $2.701 million and $3.103 million was proposed for the Rate Year.

202. The NUSCO Capital Funding expenses are net of the capitalized portions of $0.805 million for the Test Year and $0.424 million for the Rate Year.

203. The total NUSCO Capital Funding expense, prior adjustment for the capitalized amount is $3.527 million for both the Test and Rate Years.

204. The $0.424 million represents 12.03% capitalization ratio for NUSCO's payroll costs in 2013.

205. The Company currently recovers in rates, $9.6 million annually to offset the cost of non-catastrophic storms when the Company's per-storm incremental expense is less than $5 million.

206. CL&P identified the Incremental Storm Expense of $9.6 million.

207. Incremental Storm Costs differ from the storm reserve in that they are included in base rates and the expense is funded throughout the year through customer rates.

208. Catastrophic storms are those events in which CL&P incurs incremental expense in excess of $5 million.

209. The storm reserve is currently funded through the distribution rate at the level of $3 million per year.

210. The Company proposed an amount for the annual storm reserve based on storm activity during the 2010-2013 period, excluding Storm Irene, the October 2011 Nor'easter and Storm Sandy.

211. The Company proposed to utilize the storm reserve to fund $2 million per year for pre-staging costs for storms that meet specific criteria.

212. If the storm reserve accumulates a net balance of more than $50 million, then the Company will pay customers carrying charges at the weighted average cost of capital on the amount of the over-funding during the period of time that the over-funding situation exists. Conversely, the balance in the storm reserve falls below a net negative of $(50) million, then customers will pay carrying charges to the Company on the under-recovery during the period of time that under-recovery exists.

213. The Company has a means for recovery of catastrophic storm expense, which would be the request for the establishment of a regulatory asset to be recovered.

214. The Company sought recovery for storm costs that were not addressed in the Storm Cost Recovery Decision. These costs amount to $31.068 million and relate to the Windstorm of January 31, 2013, the blizzard of February 8, 2013, and remaining Hurricane Sandy costs that were not finalized at the time of the Storm Cost Recovery Decision.

215. The Company has not adjusted the 2013 storm costs to reflect the adjustments made in the Storm Cost Recovery Decision

216. CL&P proposed to utilize the storm reserve to fund $2 million per year for pre-staging costs.

217. The Company has used troubleshooters for decades.

218. The 2013 CAIDI was 107.1 minutes compared to a peer average of 102 minutes and CL&P's service scored at 604 compared to a peer average score of 655.

219. The cost of the new TSO is expected to be $10.7 million and that savings from the avoidance of cost for overtime work, associated rest periods, overtime meals and their meal time costs would save $5.7 million.

220. The total GET expense for the Test Year was $69.126 million.

221. The total GET expense proposed for the Rate Year is $85.203 million.

222. The total property tax expense for the Test Year was $66.231 million.

223. CL&P escalated known property tax mill rates to calculate the estimated property tax expense for the Rate Year.

224. The total estimated property tax expense for the 2014 list year was determined by escalating the 2013 list year's personal and real estate property mill rates by 4%.

225. The tangible personal property composite mill rate of 31.48 for the 2013 list year was escalated to 32.74 for the 2014 list year.

226. In the 2007 and 2009 CL&P Rate Case Decisions, the Authority directed CL&P not to escalate known mill rates.

227. For the 2014 list year, CL&P reported total plant additions of $233.789 million.

228. The total plant addition for calendar year 2014 is approximately $231.456 million.

229. The personal property declaration period for the 2014 list year runs from October 1, 2013 through September 30, 2014.

230. Nine months in 2014 falls within the 2014 list year declaration period.

231. Pursuant to Conn. Gen. Stat. §12-63(b)(6), the depreciated value of tangible personal property in the first year of declaration is 95% of acquisition costs.

232. The GRCF of 1.8252 was proposed for the Rate Year.

233. The GET rate of 7.072% was used calculate the proposed GRCF.

234. The total billed distribution revenue of approximately $977.414 million was used to calculate GET rate.

235. The total unbilled distribution revenue for the Test Year was approximately $1.622 million. The Company proposed rates that are based on a capital structure consisting of 50.38% common equity, 2.01% preferred stock and 47.61% long-term debt.

236. CL&P maintained its capital structure by coordinating in terms of timing and amount of common dividends paid to NU and the equity infusions that it receives from NU.

237. For the 12 months ended June 30, 2014, the Company's embedded cost of debt was 5.21%.

238. The long-term debt consists of 19 series of first mortgage bonds and nine series of pollution control revenue notes.

239. CL&P's proposed long-term embedded cost of debt is 5.45%, based on the 2013 Test Year equity ratio of 50.38%.

240. The Company proposed $116,919 in preferred stock in its capital structure as of December 31, 2015, at a cost of 4.80%.

241. CL&P has 13 series of perpetual preferred stock that was issued between 1947 and 1968. The determination of the cost of equity in this proceeding was

obtained using the DCF model and CAPM method to a proxy group of companies.

242. The Company's cost of equity testimony was prepared by Robert Hevert, a financial consultant on behalf of CL&P.

243. The Company advocated an allowed ROE of 10.20% from a range of 10.20% to 10.70%.

244. Mr. Hevert relied on a DCF model (including the Constant Growth, Quarterly Growth, and Multi-stage forms), the CAPM (including both the traditional form of the CAPM and the Empirical CAPM), and the Bond Yield Plus Risk Premium approach to develop his cost of equity results by applying to a proxy group of electric utilities.

245. Mr. Hevert did not make an explicit adjustment to his recommended ROE of 10.20% for flotation costs, but computed a 14-basis point adjustment to reasonably represent flotation costs for the Company.

246. Mr. Hevert's cost of equity calculations were primarily based on a proxy group of only 14 publicly traded utility companies.

247. To determine the composition of the proxy group, Mr. Hevert began with the universe of 47 companies from Value Line's Electric Utilities Industry.

248. Mr. Hevert applied the following screening criteria to determine his recommended proxy group: 1) consistently pay quarterly cash dividends; 2) covered by at least two utility industry equity analysts; 3) investment grade senior unsecured bond and/or corporate credit ratings from S&P; 4) regulated operating income over the three most recently reported fiscal years comprised of at least 60% of the respective totals for that company; 5) regulated electric operating income over the three most recently reported fiscal years represent at least 90% of total regulated operating income; and 6) not known to be party to a merger, or other significant transaction as of July 31, 2014.

249. Mr. Hevert calculated the dividend yield based on the proxy companies' current annualized dividends and average closing stock prices over the 30, 90 and 180 trading day periods ended July 31, 2014.

250. Mr. Hevert used a consensus of long-term earnings growth estimates from Zacks, First Call and Value Line.

251. Mr. Hevert included the sustainable growth approach to estimating a company's expected growth.

252. The Company's constant growth DCF results, including sustainable growth, produced a range of 7.58% to 10.95%.

253. Mr. Hevert used two measures of a 30-year Treasury bond yield and estimated a current rate of 3.35% and a near-term projected rate of 4.03% as the risk-free rates in the CAPM.

254. Mr. Hevert calculated three versions of the market risk premium. He relied on two forward-looking estimates and included a third estimate that is a simple average of the ex-ante method, Supply Side model, and the long-term historical average market risk premium.

255. Mr. Hevert produced CAPM results in the range of 9.46% to 11.96%, a decrease from the prior range of 9.74% to 12.16%.

256. Mr. Hevert included the ECAPM analysis in estimating the cost of equity, which is another variation of the CAPM.

257. Besides the traditional CAPM and ECAPM, Mr. Hevert evaluated the cost of equity utilizing the bond yield plus risk premium method.

258. The OCC's cost of capital witness, Dr. Woolridge, advocated a 8.90% ROE in this proceeding based on the capital structure proposed by CL&P which includes a common equity ratio of 50.38%.

259. Using the proposed Test Year capital structure and senior capital cost rates, OCC recommended an overall rate of return of 7.14%.

260. Dr. Woolridge employed the use of the DCF and CAPM approaches to a 32-member electric proxy group, as well as, Mr. Hevert's proxy group of companies.

261. The average S&P bond ratings for the Woolridge and Hevert proxy groups are both BBB+, while CL&P's bonds are rated A-.

262. In developing a fair rate of return for CL&P, Dr. Woolridge primarily relied on the DCF model to estimate the cost of equity and applied it to the both Mr. Hevert's proxy group and his 32-member proxy group.

263. Using the constant growth version of the DCF method, Dr. Woolridge first calculated the dividend yield by taking the current annual dividend and the 30-day, 90-day and 180-day average stock prices as of July 17, 2014. To reflect the growth over the coming period, Dr. Woolridge adjusted the dividend yields by one-half the expected dividend growth resulting in an adjusted dividend yield of 3.9% for Woolridge's proxy group and 4.0% for Hevert's proxy group.

264. For the growth component of the DCF calculation, Dr. Woolridge employed 13 measures of growth, of which 6 measure historic growth, and 7 are *Value Line* or Wall Street analysts' projections of growth, giving primary weight to the projected EPS growth rate forecasts of analysts.

265. To derive the overall growth rate for the proxy groups, Dr. Woolridge used the midpoint of the median range for each resulting in a DCF growth rate of 4.875%

for Woolridge's proxy group and 5.0% for Hevert's proxy group, giving greater weight to the projected growth rate figures.

266. Dr. Woolridge calculated equity costs rates of 8.80% and 9.0%, for Woolridge and Hevert's proxy group, respectively.

267. Dr. Woolridge performed a CAPM analysis using both proxy groups.

268. Dr. Woolridge elected to use 4.0% as the risk-free rate in the CAPM analysis.

269. The median betas for the companies in Woolridge's and Hevert proxy groups are 0.75% for both.

270. To determine an equity risk premium, the OCC reviewed the results of over 40 equity risk premium studies and surveys performed over the past decade.

271. Dr. Woolridge claimed that much of the data indicates that the market risk premium is in the 4.0% to 6.0% range and the midpoint of 5% is used as the market risk premium for OCC's CAPM analysis.

272. Dr. Woolridge's CAPM resulted in a cost of equity of 7.80% for both proxy groups.

273. The OCC concluded that the appropriate equity cost rate for the proxy groups is in the 7.80% to 9.00% range.

274. Dr. Woolridge did not take into consideration the impact of the Company's proposed decoupling mechanism nor the earnings sharing mechanism on the OCC recommended ROE. He concurred that the mechanisms are reflected in the lower risk of the company.

275. Dr. Woolridge provided the authorized ROEs in 18 rate cases in 2013 and 2014 involving distribution-only electric utilities. There are no authorized ROEs of 10% or higher, and the average for the distribution-only electrics is 9.48%.

276. There is a declining trend in authorized ROEs, particularly for distribution-only utilities. According to data from Regulatory Research Associates, the average of 101 reported electric utility rate case ROEs authorized by commissions in 2012, 2013 and so far in 2014, is 9.91%, with a reported range of 8.72% to 10.95%.

277. The average reported ROE for distribution-only utilities was 9.57%, which is 63 basis points lower than CL&P's proposed ROE.

278. In 16 recent utility rate cases in which Mr. Hevert provided expert testimony, the approved ROE decided in each case was lower than Mr. Hevert's recommended ROE in all 16 cases.

279. The AG generally supported the OCC's cost of capital testimony and its recommended ROE of 8.9%.

280. To calculate a flotation adjustment, Mr. Hevert modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs.

281. The Company did not identify any test-year flotation costs.

282. CL&P has incurred the issuance expenses associated with NU's dividend reinvestment plan, which is only at the parent company level.

283. The record also indicates that NU has not executed any common stock offerings since the filing of CL&P 2009 Rate Case.

284. Interest rates and long-term utility bond yields remain at historical low levels and are below the levels existing at the time of the 200r CL&P Rate Case.

285. The economic outlook now for several years has promised economic recovery and the rise of interest rates which have not occurred.

286. The average ROEs for the electric and gas industries continue to trend downward.

287. At the time CL&P's last ROE was set at 9.40%, the annual average allowed ROE for the electric industry was 10.48% for 2009.

288. In 2013 to 2014, there have been no authorized ROEs of 10% or higher and the average for the distribution-only electrics is 9.48%.

289. The Company and OCC did not suggest an adjustment to their recommended ROEs to quantify an impact for decoupling.

290. Revenue stabilization and cost recovery mechanisms, such as decoupling, are already reflected in current market valuations of the proxy companies.

291. Both S&P and Fitch upgraded CL&P's ratings due to the merger between NU and NSTAR.

292. 2009 CL&P Rate Case, the Company has increased its S&P bond rating from BBB to the present A-, two notches.

293. As of June 24, 2014, the Company has credit ratings of A- (outlook: Positive), Baa1 (outlook: Stable), and BBB+ (outlook: Stable) from S&P, Moody's and Fitch, respectively.

294. Since 2009, the Company has a stronger times interest earned ratio, fixed coverage ratio, profit margin, return on total assets and return on total capital.

295. The investment risk of public utilities is still relatively low compared to the market as a whole (1.0 beta) as evidenced by the drop in NU's beta from .80 in 2009 to .75 currently.

296. CL&P continues to maintain a strong financial position, limited risk profile, visible forward earnings stream, a stable dividend yield, strong balance sheet and strong cash position.

297. Despite the decline in interest rates, utilities continue to outperform most sectors of the bond market.

298. The cost of equity for the electric industry is among the lowest of all industries in the U.S.

299. The Authority has established the sharing threshold at the Company's allowed ROE with the sharing distributed equally with 50% to shareholders and 50% for the customers.

300. Since 1999, the Company has operated under an ESM whereby earnings in excess of the allowed ROE are shared with ratepayers.

301. Conn. Gen. Stat. §16-19(g) allows the Authority to review a company's earnings if an earned ROE exceeds a company's authorized ROE by 1% point for a period of six consecutive months, equivalently two fiscal quarters.

302. The Authority has a long tradition of using an ESM and has approved these for companies as an incentive to shareholders.

303. Implementation of an ESM allows shareholders to capture a portion of potential overearnings and avoid an overearnings financial review that would be otherwise initiated by the Authority.

304. ESMs have been implemented in the past for electric, gas and water utilities.

305. The current ESM is also consistent with other recent ESMs that were approved by the Authority.

306. In its 2011 Storm Decision, the Authority stated that it was establishing a rebuttable presumption that CL&P should have imposed on it an appropriate reduction to its allowed return on equity in its next ratemaking proceeding as a penalty for poor management performance and to provide incentives for improvement.

307. In the Merger Decision, the Authority approved the merger agreement between Northeast Utilities and NSTAR.

308. A condition of the merger settlement agreement provided that any future recovery of transaction costs are subject to Authority review and approval in a future rate proceeding.

309. This docket is the first rate case since the merger was approved.

310. The Authority found in the Merger Docket that total net benefits of approximately $783.8 million were expected on an overall, enterprise-wide basis with an estimated $301.8 million allocable to CL&P's transmission and distribution operations.

311. The Company submitted an updated merger integration report integration forecasting an increase, in merger savings on an enterprise-wide basis of $92.8 million for a total of $876.6 million.

312. The decoupling statute requires the adjustment or reconciliation be made on the basis of "actual distribution revenues."

313. No other utility in Connecticut has sought and the Authority has not approved any such exception for revenues to be retained in excess of those allowed to meet revenue requirements.

314. Decoupling is not a rate developed to recover underlying, prudently incurred costs; it is a true-up mechanism for revenues previously designed fully in accordance with the Authority's just and reasonableness responsibility.

315. The potential loss of revenue from new service customers is more than balanced from the protection ratepayers stand ready to provide should sales decrease for any reason.

316. Decoupling is only a true-up mechanism that involves minimal dollars in comparison to total distribution revenues.

317. Decoupling is not an appropriate alternative to increasing fixed charges.

318. CL&P traditionally used statistically adjusted end-use models to forecast sales by customer class.

319. The Company performed a weather normalization study in developing the rate year sales forecast and associated revenues.

320. In 2011, CL&P lost approximately 159 GWh, or 2.2% of its sales for the affected period, due to Hurricane Irene and the October 2011 snowstorm.

321. In 2012, CL&P lost approximately 86 GWh, or 2.6% of its sales for the affected period, due to Hurricane Sandy.

322. The Company recently increased its C&LM spending, and will lose additional sales which are not reflected in historical sale trends, that only include the base conservation savings.

323. Rate Year revenues for reconnect fees for 2013 are low compared to prior years.

324. The Rent from Electric Property, could not be calculated as the billing determinants for pole attachments is not available.

325. CL&P has an agreement with Verizon from 1956 that gives all recurring attachment revenues for the communications gain on jointly owned poles to Verizon, and pre-dates the existence of cable television and fiber pole attachments.

326. CL&P did not recover all of its pole attachment make-ready expense in the Test Year.

327. CL&P does not have explicit authority to collect all make-ready expenses from pole attachers.

328. A 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.

329. A COSS is an invaluable tool for documenting equity and establishing revenue requirements and tariff charges by customer class.

330. The Company followed the detailed methodology consistently approved by the Authority in past rate case Decisions.

331. The Company relied on its COSS results when designing rates.

332. FERC established a new operating standard designed to save energy losses in transformers.

333. The NARUC Manual requires plant installed to service customers and meet their peak demand, must be segmented into customer and demand related costs.

334. The NARUC Manual states that the customer component of distribution facilities is that portion of costs which varies with the number of customers.

335. The NARUC Manual recommends that either the minimum intercept method or other methods like the minimum distribution system method be undertaken to discern customer and demand cost components.

336. The Authority held in Docket No. 90-12-03 that the simplicity of the minimum-size methodology warrants its continued use by CL&P in future COSS.

337. A genuine, but minimal, distribution system is necessary for a utility to stand ready at no load or to serve nominal loads.

338. In Docket No. 05-06-04, the Authority rejected the OCC's recommendations that no costs be allocated based on the number of customers.

339. In Docket No. 08-07-04, the Authority rejected the OCC's request for allocation on the basis of demand only.

340. Poles and lines are installed to expand circuits to reach new off-circuit customers.

341. Some minimum size cable is necessary to simply reach all customers.

342. kVA levels differ dramatically between residential neighborhoods and industrial parks.

343. Transformers are needed to expand circuits to reach customers and are sized to reflect differing kVA demands.

344. Newer transformer designs will operate with less energy lost as heat.

345. The COSS methodology submitted by the Company can be relied upon for designing rates.

346. To reduce interclass subsidies, all classes should be moved closer to their cost to serve, or closer to the system average ROR, while applying the principles of rate gradualism.

347. The farther the class is from the system average, the larger the percentage increase/decrease necessary to align the class revenues to the average.

348. To reduce inequities between classes, it is necessary to align the rate classes as close to the system ROR as possible.

349. The Company's rate design moved rates in each rate class closer to their actual cost of service, both at a total class level and with respect to the prices for distribution service within each rate class.

350. The Company's rate design moved the ROR for each rate class closer to the average ROR by allocating a greater/lesser than average percentage distribution increase, depending on their current ROR.

351. CL&P's rate design decreased or eliminated per kWh charges, and moved customer and demand charge rates closer to their cost-of-service levels.

352. CL&P's rate design proposal was designed to collect a total distribution revenue increase of $231.6 million.

353. For Rate 1, CL&P set a distribution rate revenue target of $570.4 million, an increase of $148.2 million or 35.11% over its current distribution revenue of $422.5 million.

354. CL&P's rate design for Rate 1 included a 59% increase to the Customer Charge and a 2.64% increase to the per-kWh Charge.

355. If the COSS classified distribution facilities on a full demand basis, without classifying the plant costs as customer-related, the study would support a customer charge no higher than $11.68.

356. The low-use customers in Rate 1 will face the largest percentage bill increases from the proposed customer charge increase.

357. The OCC, BETP, ENE and AG objected to the 59% increase in the customer charge.

358. The Authority received an unprecedented number of comments from customers, public officials and consumer advocates on the proposed rate increase, especially the 50% increase in the Rate 1 Customer Charge.

359. Decoupling removes any Company sales-related disincentive to promote energy efficiency and distributed generation, and assures cost-recovery for the Company.

360. A potential 10% savings in distribution charges has not induced a large customer migration to TOD pricing.

361. CL&Ps rate design for Rates 27, 30 and 40 include increases to the Customer Charge in excess of 40%.

362. New rates will not be implemented until after final approval of the Rate Plan.

363. The customer bill impact of the distribution rate increase will be mitigated by a subsequent decrease of the storm related costs which will be removed from the NBFMCC effective January 1, 2015.

364. Recurring charges for pole attachments are typically fees for rental of pole space, and non-recurring fees typically include items such as make-ready costs.

365. Municipal Rate customers are allowed an exemption from pole attachment fees for their first attachment on any pole.

366. The pole attachment rates are billed on a semi-annual basis.

367. The Pole Attachment Order methodology uses historic (embedded) costs while CL&P uses a combination of historic and reproduction (marginal) costs, which the FCC has expressly rejected.

368. The Pole Attachment Order methodology applies cost allocators of 66% in urban areas and 44% in rural areas while CL&P applies higher cost allocators of 69.18% in urban areas and 45.38% in rural areas.

369. The Pole Attachment Order methodology allocated pole costs using a presumption of 13.5’ of usable space on the pole to derive a space allocation factor while CL&P uses 12.33’ without providing a pole survey.

370. NECTA conducted a Pole Survey and calculated a usable space factor for pole attachments of 14.57'.

371. In Docket No. 09-12-05, the Authority approved the unbundling of street lighting rates into their functional components.

372. The Company's unbundled rate design of Rate 116 set pricing for the system component of rates and the equipment and O&M components of rates.

373. The Company designed a two-part charge for Rate 117 consisting of customer and demand components that applies to applicable fixtures connected to the CL&P's distribution system.

374. The revenue targets for customer and demand were derived by applying a 75% / 25% proportion of demand and customer costs, respectively.

375. For Rate 116, additional equipment and O&M charges apply.

376. The same methodologies for determining the system, equipment and O&M rates for other Rate 117 offerings have been applied in developing proposed new LED street lighting distribution rates.

377. The proposed rates in the T&C for Delivery Service were developed based on the cost of providing service.

378. In the past, the Authority approved CL&P's request to discontinue the surge protection program.

379. CL&P offers a TOD rate option, Rate 7, for residential non-heating customers, of which Rate 5 customers may elect to receive service.

380. Rate 7 was designed based on the service characteristics of the non-heating residential class Rate 1, and on methodologies and guidelines developed and approved by the Authority.

381. Less than 500 customers receive service on Rate 7 compared to over 1.1 million customers on Rate 1 and Rate 5.

382. Rate 5 is a legacy tariff and new customers are no longer allowed to take service under that rate.

383. The Reconnection at the Meter Charge has not changed in many years, despite increases to general rates.

384. CL&P's standard bill form, termination notice and customer rights notice comply with applicable regulations.

385. For calendar year 2014, less than 1.5% of bills issued were estimated.

386. CL&P's estimated bill form complies with applicable regulations.

387. CL&P's policies and procedures for the administration of customer security deposits comply with applicable regulations.

388. In November 2012, CL&P discontinued the practice of on-site energy audit service appointments at a customer's location.

389. NUStart became a one-year program in calendar year 2013.

390. CL&P's Call Center performance statistics were acceptable as filed.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

Based on the evidence presented in this proceeding, the Authority finds allowed revenues of $1.033 billion to be appropriate for CL&P in the Rate Year as detailed in Appendix A. This is a reduction of $93 million from the Company's adjusted cumulative request of $1.127 billion and a $134.076 million increase or 13.9% to present revenues. The Authority allows the Company an allowed rate base of $3.233 billion. The Authority approves an allowed ROE of 9.02% for 2015, inclusive of a one year penalty of 15 basis points for 2011 Storms response. The allowed capital structure consists of 50.38% common equity, 2.01% preferred stock, and 47.61% long-term debt components. The revenue requirement adjustments as authorized herein will be sufficient to enable the Company to operate successfully, maintain its financial integrity, attract capital, compensate its investors for the use of their money and the risks assumed, and maintain high quality service. New rates will become effective for usage on and after December 1, 2014. The Authority will reopen this proceeding for the purpose of further reviewing and ruling on issues identified herein related to the repair tax deductions and accumulated deferred income taxes.

B. ORDERS

For the following Orders, 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 PURA's website at www.ct.gov/pura. Submissions filed in compliance with the PURA's Orders must be identified by all three of the following: Docket Number, Title and Order Number.

1. Beginning on December 17, 2014, the Company, for each restoration event that it incurs in excess of $20 million, shall submit to the Authority its proposed cost recovery utilizing its standard accounting practices as well as a proposed recovery using the accounting treatment that was utilized in the Decision in Docket No. 13-03-23. This filing shall be made with the Authority within 30 days of full restoration of the event.

2. No later than December 31, 2014, the Company shall submit a final Rate Plan for Authority approval that incorporates the directives herein as outlined in Section II.J.5. Rate Design, Section II.J.8. Tariff Changes, and also include the following:

   a. the CATV Rate and Telecom Rate as discussed in Section II.J.6. Pole Attachment Rates and the Company shall prorate the December charge in accordance with its proposal; and
   b. a new Decoupling Tariff Rider as discussed in Section II.H. Decoupling.

3. No later than January 30, 2015, CL&P shall file a copy of its 2013 income tax return with the IRS with the Authority. The filing shall include all applicable schedules and forms supporting tax elections made or requested. Additionally, the filing shall include a worksheet showing portions of the tax depreciation deductions reported on Form 4562 that are applicable to distribution plant-in-service.

4. No later than January 30, 2015, CL&P 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 20 business days prior to the effective date of such changes.

5. No later than February 16, 2015, the Company shall file a final-rates COSS reflecting rate year billing determinants, the financial profile approved in this Decision and the then current rates developed in accordance with the Rate Plan approved herein.

6. No later than March 31, 2015 and each year thereafter until its next rate case, the Company shall report the CAIDI for the second and third shifts and for weekends and the average number of contract workers staffing each work period to demonstrate the change that the new TSO had on reliability for these periods and the overall system and report the annual contractor costs of the new TSO.

7. No later than March 31, 2015, 2016 and 2017, the Company shall provide the Authority with a report of actual construction program capital spending by Initiative or category for the preceding year. 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.

8. No later than April 1, 2015, the Company shall report on the status of introducing a phase-out formula concerning revenue true-ups in their next scheduled CAM and FMCC reconciliation filings.

9. No later than April 1, 2015, CL&P shall provide a proposal that addresses the OCC's concerns regarding its joint pole agreement with Verizon.

10. No later than September 30, 2015, CL&P shall file a copy of its 2014 Federal income tax return with the Authority. The filing shall include all applicable schedules and Form 3115 filed requesting accounting changes regarding the RTD election pursuant Revenue Procedure 2012-20. Additionally, the filing shall

include a worksheet showing portions of the tax depreciation deductions reported on Form 4562 that are applicable to distribution plant-in-service and a summary of the RTD amounts for the appropriate calendar years.

11. No later than November 30, 2015 and 2016, the Company shall provide the Authority with the budget of construction program capital spending by initiative or category for the following year.

12. No later than February 15, 2016 and annually thereafter, the Company shall file its proposed decoupling rate for the upcoming 12-month period.

13. Beginning January 31, 2016, and annually thereafter for the term of this rate plan, the Company shall report to the Authority unused amounts of pre-staging costs that are transferred to the storm reserve.

14. In its first Decoupling Mechanism reconciliation filing, the Company shall adjust its allowed revenue requirement target to reflect the ROE penalty imposed in Section II.F.4 ROE Penalty.

15. In its next rate case, the Company shall submit a:

    a. Depreciation Study.
    b. Complete and well documented analysis of expected service periods for its existing and new software systems and provide such analysis to the Authority prior to its next rate proceeding.
    c. Report on the annual CAIDI and JD Power service scores for CL&P since 2013 and its peer group and justify the effect that the new TSO had on these results. COSS that is methodologically consistent with the study performed in the instant application.
    e. Second COSS that utilizes a zero-intercept methodology for segmenting plant included in the current minimum-size-of-facilities method into customer and demand categories.
    f. Rate design that utilizes a rate year COSS that reflects the methodology approved in the instant case.

V. RATE MODEL

A. 2015

1. Income Statement

THE CONNECTICUT LIGHT AND POWER COMPANY - DN 14-05-06
INCOME STATEMENT 12/16/2014
ELECTRIC - RATE YEAR STARTING DECEMBER 1, 2014
FROM APPLICATION FILED 09/22/2014

PER CENT REVENUE INCREASE ALLOWED = **14.3058%**

	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	TABLE II	FINAL CHANGES	TABLE III
OPERATING REVENUES	$905,882	$616	$906,498		$906,498
OPERATING REVENUES - OTHER		0	0		0
RATE REQUEST	221,098	0	221,098	(91,416)	129,682
TOTAL REVENUES	1,126,981	616	1,127,597	(91,416)	1,036,180
OPERATION & MAINTENANCE EXPENSE	$375,418	(21,366)	$354,052	(277)	353,775
OTHER O&M		0	0		0
MISC. EXPENSE		0	0		0
DEPRECIATION EXPENSE	150,372	(7,440)	142,932		142,932
AMORTIZATION EXPENSE	61,662	34	61,696		61,696
MISC. EXPENSE		0	0		0
TAXES, SALES & PAYROLL	11,449	(414)	11,035		11,035
GROSS EARNINGS TAXES	85,203	(96)	85,107	(6,455)	78,653
PROPERTY TAXES	81,435	(1,988)	79,447		79,447
PROVISION FOR DEF. INCOME TAXES, NET	27,885	3,039	30,924	0	30,924
STATE TAXES	6,744	2,603	9,347	(7,622)	1,725
FEDERAL TAXES (CURRENT)	60,700	9,212	69,912	(26,972)	42,940
INVESTMENT TAX CREDIT	(954)	0	(954)		(954)
TOTAL OPERATING EXPENSES	$859,914	(16,415)	$843,499	(41,325)	$802,173
INCOME FROM LEASE OF UTILITY PLANT	0	0	0		0
OPERATING INCOME	$267,067	$17,031	$284,098	(50,091)	234,008

2. Rate Base

THE CONNECTICUT LIGHT AND POWER COMPANY - DN 14-05-06
RATE BASE LAST REVIEW DATE 12/16/2014
ELECTRIC - RATE YEAR STARTING DECEMBER 1, 2014

	REVISED PROFORMA	AUTHORITY ADJUSTMENTS	TABLE I
UTILITY PLANT IN SERVICE	5,257,802	(4,510)	$5,253,292
PLANT 2			0
LESS: CONS. WORK IN PROGRESS		0	0
LESS: ACCUM DEP AND AMORT	1,312,534	(3,720)	1,308,814
	-----------	-----------	-----------
NET PLANT	3,945,268	(790)	3,944,478
	-----------	-----------	-----------
PLUS:			
MATERIALS & SUPPLIES	$54,818	0	54,818
WORKING CAPITAL	17,230	(1,869)	15,361
PREPAYMENTS	4,655	0	4,655
DEFERRED TAXES - CIAC	38,418	0	38,418
ACCUM. DEFERRED INCOME TAXES - FAS 1(	391,860	0	391,860
REGULATORY ASSET - FASB 158		0	0
DEFERRED ASSETS, NET OF TAXES	191,788	(17)	191,771
LESS:			
ACCUM. DEFERRED INCOME TAXES	$789,750	171,583	961,333
CUST. ADVANCES AND DEPOSITS	15,406	0	15,406
STORM RESERVES		0	0
DEFERRED INCOME TAXES - FAS 158		0	0
ALLOWANCE FOR BAD DEBT		0	0
PENSION LIABILITIES		0	0
RESERVES, NET OF TAXES	40,555	(1,775)	38,780
ACCUM. DEFERRED INCOME TAXES - FAS 1(	391,860	0	391,860
	-----------	-----------	-----------
RATE BASE	3,406,466	(172,484)	3,233,982
	===========	===========	===========
RETURN ON RATE BASE	7.83%	7.24%	7.24%
	-----------	===========	-----------
OPERATING INCOME	266,739	(32,731)	234,008
	===========	===========	===========

B. 2016

1. Income Statement

THE CONNECTICUT LIGHT AND POWER COMPANY - DN 14-05-06
INCOME STATEMENT 12/15/2014
ELECTRIC - RATE YEAR STARTING DECEMBER 1, 2015
FROM APPLICATION FILED 09/22/2014

PER CENT REVENUE INCREASE ALLOWED = **14.7905%**

	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	TABLE II	FINAL CHANGES	TABLE III
OPERATING REVENUES	$905,882	$616	$906,498		$906,498
OPERATING REVENUES - OTHER		0	0		0
RATE REQUEST	221,098	0	221,098	(87,022)	134,076
TOTAL REVENUES	1,126,981	616	1,127,597	(87,022)	1,040,574
OPERATION & MAINTENANCE EXPENSE	$375,418	(21,366)	$354,052	(264)	353,788
OTHER O&M		0	0		0
MISC. EXPENSE		0	0		0
DEPRECIATION EXPENSE	150,372	(7,440)	142,932		142,932
AMORTIZATION EXPENSE	61,662	34	61,696		61,696
MISC. EXPENSE		0	0		0
TAXES, SALES & PAYROLL	11,449	(414)	11,035		11,035
GROSS EARNINGS TAXES	85,203	(96)	85,107	(6,144)	78,963
PROPERTY TAXES	81,435	(1,988)	79,447		79,447
PROVISION FOR DEF. INCOME TAXES, NET	27,885	3,039	30,924	0	30,924
STATE TAXES	6,744	2,604	9,348	(7,255)	2,093
FEDERAL TAXES (CURRENT)	60,700	9,216	69,916	(25,676)	44,241
INVESTMENT TAX CREDIT	(954)	0	(954)		(954)
TOTAL OPERATING EXPENSES	$859,914	(16,409)	$843,505	(39,339)	$804,166
INCOME FROM LEASE OF UTILITY PLANT	0	0	0		0
OPERATING INCOME	$267,067	$17,025	$284,092	(47,683)	236,409

2. Rate Base

THE CONNECTICUT LIGHT AND POWER COMPANY - DN 14-05-06
RATE BASE LAST REVIEW DATE 12/15/2014
ELECTRIC - RATE YEAR STARTING DECEMBER 1, 2015

	REVISED PROFORMA	AUTHORITY ADJUSTMENTS	TABLE I
UTILITY PLANT IN SERVICE	5,257,802	(4,510)	$5,253,292
PLANT 2			0
LESS: CONS. WORK IN PROGRESS		0	0
LESS: ACCUM DEP AND AMORT	1,312,534	(3,720)	1,308,814
	-----------	-----------	-----------
NET PLANT	3,945,268	(790)	3,944,478
	-----------	-----------	-----------
PLUS:			
MATERIALS & SUPPLIES	$54,818	0	54,818
WORKING CAPITAL	17,230	(2,451)	14,779
PREPAYMENTS	4,655	0	4,655
DEFERRED TAXES - CIAC	38,418	0	38,418
ACCUM. DEFERRED INCOME TAXES - FAS 10	391,860	0	391,860
REGULATORY ASSET - FASB 158		0	0
DEFERRED ASSETS, NET OF TAXES	191,788	(17)	191,771
LESS:			
ACCUM. DEFERRED INCOME TAXES	$789,750	171,583	961,333
CUST. ADVANCES AND DEPOSITS	15,406	0	15,406
STORM RESERVES		0	0
DEFERRED INCOME TAXES - FAS 158		0	0
ALLOWANCE FOR BAD DEBT		0	0
PENSION LIABILITIES		0	0
RESERVES, NET OF TAXES	40,555	(1,775)	38,780
ACCUM. DEFERRED INCOME TAXES - FAS 10	391,860	0	391,860
	-----------	-----------	-----------
RATE BASE	3,406,466	(173,066)	3,233,400
	===========	===========	===========
RETURN ON RATE BASE	7.83%	7.31%	7.31%
	-----------	===========	-----------
OPERATING INCOME	266,739	(30,329)	236,409
	===========	===========	===========

DOCKET NO. 14-05-06 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

This Decision is adopted by the following Commissioners:

Arthur H. House

Michael A. Caron

This Decision is adopted, in part, and dissented to, in part, by the following Commissioner:

John W. Betkoski, III

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.

Nicholas E. Neeley

Nicholas E. Neeley
Acting Executive Secretary
Public Utilities Regulatory Authority

12/17/14
Date

<u>DOCKET 14-05-06</u>
APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY FOR A RATE INCREASE

<u>DISSENTING OPINION, IN PART, OF VICE CHAIRMAN JOHN W. BETKOSKI, III</u>

Every Commissioner at the Connecticut Public Utilities Regulatory Authority (PURA or Authority) has the right to a dissenting opinion. I'm exercising this right at this time. My dissenting opinion in the instant proceeding was not an easy decision. However, my experience in utility rate making is the basis for my decision. My dissenting opinion is on the allowed return on equity (ROE) authorized by this Authority.

The determination of the cost of capital was a large part of this CL&P rate case proceeding. The cost of capital includes both the cost of equity and the cost of debt. The basis for the determination of an overall cost of capital is articulated in <u>Federal Power Commission v. Hope Natural Gas Company</u>, 320 US 591 (1944), in which the Court established criteria to determine cost of capital allowances. In its Decision, the Court determined that companies need to be allowed to earn a level of revenues sufficient to enable them to operate successfully, maintain their financial integrity and to attract capital and compensate their investors for their risk. By Connecticut law, utilities are entitled to a level of revenues that will allow them ". . . to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interest both existing and foreseeable." Connecticut General Statutes (Conn. Gen. Stat.) §16-19e(a)(item 4).

To determine a rate of return (ROR) on rate base that is appropriate for a utility's overall cost of capital, the Authority first identifies the components of a utility's capital structure. A capital structure is defined as the permanent long-term financing of a company which consists of long-term debt, preferred stock, and equity. The cost of each capital component is then determined and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the utility's overall cost of capital, which becomes the allowed rate of return on rate base. The most difficult and controversial cost of capital component to determine is the ROE. My dissension centers on the determination of this ROE.

In order to determine an allowed ROE the risks that investors face must be considered as well as what a rational investor's expectations are. An investment of any kind results in an opportunity cost to the investor. This opportunity cost is best thought of as the cost of using capital for a certain investment as measured by the benefit of revenues given up (opportunity loss) by not using the capital in the next best alternative investment. An equity investor forgoes the use of their money in exchange for a set of expectations being a series of cash dividend payments, recovery of their initial investment, and also some growth in their initial investment. The key wordin this is expectations because the concept of risk relates to expected not realized returns on an investment.

I find that the Authority has properly calculated the discounted cash flow (DCF), capital asset pricing model (CAPM), and risk premium methodologies in coming to a conclusion of a 9.17% ROE. Market data was used as close to the date of this decision as possible to make for a timely allowed market based ROE. The simple fact is I believe this Authority should consider the use of data of average ROE's as published by Regulatory Research Associates (RRA). This is a well-respected publication used by state commissions as well as utilities. ROE data from other state commissions should also be used. From my seventeen years as a commissioner at this Authority, I have found that RRA has been consistently used as a benchmark for ROE determination. The ROE awarded by a commission should be commensurate with other utilities in the same industry. If a utility consistently has a lower ROE than peer utilities, this will put that utility at a disadvantage in attracting investor capital.

CL&P is currently at an allowed ROE of 9.40% and requested an allowed ROE of 10.20% in this proceeding. The record indicates that RRA, calculated the average of 101 reported electric utility rate case ROEs authorized by commissions in 2012, 2013 and so far in 2014, is 9.91%, with a reported range of 8.72% to 10.95%. Chriss PFT, p, 18. These electric utilities are both distribution and integrated.

The record also indicates that distribution only electric utilities allowed ROEs for 2013 and 2014 are the following:

Date	State	Utility	Docket/Case Number	Authorized ROE
1/16/2013	Texas	Cross Texas	Docket No. 40604	9.60%
1/16/2013	Texas	Wind Energy Transmission Texas	Docket No. 40606	9.60%
2/22/2013	Maryland	Baltimore Gas and Electric Co.	Case No. 9299	9.75%
3/14/2013	New York	Niagara Mohawk Power Corp.	Docket No. 12-E-0201	9.30%
5/1/2013	Ohio	Duke Energy Ohio Inc.	Case No. 12-1682-EL-AIR	9.84%
6/21/2013	New Jersey	Atlantic City Electric Co.	Docket No. ER-12121071	9.75%
7/12/2013	Maryland	Potomac Electric Power Co.	Case No. 9311	9.36%
8/14/2013	Connecticut	United Illuminating Co.	Docket No. 13-01-19	9.15%
10/3/2013	Texas	Southwestern Electric Power Co	Docket No. 40443	9.65%
12/9/2013	Illinois	Ameren Illinois	Docket No. 13-0301	8.72%
12/13/2013	Maryland	Baltimore Gas and Electric Co.	Case No. 9326	9.75%
12/18/2013	Illinois	Commonwealth Edison Co.	Docket No. 13-0318	8.72%
2/20/2014	New York	Consolidated Edison Co. of NY	Case No. 13-E-0030	9.20%
3/17/2014	New Hampshire	Liberty Utilities Granite St	Docket No. DE-13-063	9.55%

3/26/2014	District of Columbia	Potomac Electric Power Co.	Formal Case No. 1103-2013-EL	9.40%
4/2/2014	Delaware	Delmarva Power & Light Co.	Docket No. 13-115	9.70%
5/16/2014	Texas	Entergy Texas Inc.	Docket No. 41791	9.80%
5/30/2014	Massachusetts	Fitchburg Gas & Electric Light	DPU 13-90	9.70%
7/2/2014	Maryland	Potomac Electric Power Co.	Case No. 9336	9.62%
			Average	9.48%

Woolridge PFT, Exhibit JRW-12, p. 3.

Using the allowed ROE data from RRA and other sources is much like the comparable earnings (CE) methodology in determining an allowed ROE. The CE methodology in its simplest form compares other utilities with the same risk characteristics with the utility in question and averaging the returns found to be applicable. I believe the risk characteristics of the electric companies found in RRA are comparable to Connecticut Light and Power Company (CL&P). More importantly’ I believe investors consider the whole electric utility industry and look to the opportunity of electric companies to earn a fair rate of return as embodied in the allowed ROE authorized by their various state utility commissions. With this said, my experience tells me that critics will say that the drawback of using this methodology is stale data from allowed returns that were set some time ago so as to preclude current market data. I counter this argument with the fact that these allowed ROEs, whenever set, are currently in effect and that the electric utility has the opportunity to earn revenues based on those allowed ROEs. Investors have a choice as to where to put their investment capital and in my opinion one of the paramount factors in investor decision making is how high the allowed return is for a specific electric utility. Other ROE proxies that can be used, for a determination of an allowed ROE for CL&P, are an allowed ROE for Western Massachusetts Electric Company (WMECO) currently at 9.60% and Public Service of New Hampshire (PSNH) at an allowed ROE of 9.67% which are both electric utility operating companies of CL&P’s parent company Northeast Utilities (NU).

The determination of an allowed ROE is a balance between revenue requirements paid by ratepayers and the financial integrity of CL&P. The higher the allowed ROE the greater the revenue requirement paid by ratepayers. However, the higher the ROE, the greater is the financial integrity of CL&P. This is shown in the credit rating of CL&P which is currently at an A- credit rating. This credit rating is a primary factor in the cost of borrowing which is an expense passed on to ratepayers. An allowed ROE needs to strike a balance between increased cost to ratepayers and a decrease in the cost of debt for CL&P.

The Parties offer a range of reasonableness for an allowed ROE, as determined by the expert witness for CL&P of 10.20% and the expert witness for the Office of Consumer Counsel (OCC) of 8.90%. In addition I am aware that CL&P is a distribution only electric utility and as such does not have the risks associated with the generation component of integrated utilities. Since CL&P is a distribution only electric utility it is most closely risk comparable to other distribution only electric companies. Therefore I believe a 9.48% allowed ROE is reasonable which falls within the range of reasonableness of 8.90% and 10.20% established by the expert witnesses in this proceeding.

I believe this 9.48% allowed ROE will lower CL&P's cost of debt by maintaining the A- credit rating of CL&P. I find that this 9.48% ROE should produce operating income sufficient for CL&P to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate its investors for the risk assumed.

Submitted by:

Comissioner John W. Betkoksi, III
Vice Chairman
Public Utilities Regulatory Authority