The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 17-05-B January 5, 2018

Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism.

ORDER ESTABLISHING EVERSOURCE'S RATE STRUCTURE

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I. INTRODUCTION

On January 17, 2017, NSTAR Electric Company ("NSTAR Electric")[1] and Western Massachusetts Electric Company ("WMECo"), each doing business as Eversource Energy (collectively, "Eversource" or "Companies") filed a petition with the Department of Public Utilities ("Department") seeking approval of increases in base distribution rates for electric service pursuant to G.L. c. 164, § 94 ("Section 94"), as well as other proposals. On June 9, 2017, the Department issued an Interlocutory Order that designated to a separate procedural track the rate design issues in this case. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, Interlocutory Order at 13-14 (June 9, 2017) ("Interlocutory Order"). Pursuant to the Interlocutory Order, the Department determined that it would issue a separate Order addressing rate design issues. Interlocutory Order at 14.

On November 30, 2017, the Department issued a final Order establishing Eversource's revenue requirement and resolving all issues in this case, other than rate design issues or other related issues specifically reserved for resolution in the instant Order. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05 (November 30, 2017) (D.P.U. 17-05 Order). The Companies' various non-rate design-related proposals and the Department's decisions regarding the same are discussed in

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1 NSTAR Electric is comprised of three operating units – Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company (Exh. ES-RDP-1, at 5). See also BEC Energy/Commonwealth Energy Systems, D.T.E. 99-19 (1999).

full detail in that Order. Consistent with the Interlocutory Order, the instant Order will focus on the Companies' rate design proposals.

II. PROCEDURAL BACKGROUND[2]

On January 25, 2017, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E (a). The following entities were granted full party intervenor status: (1) Acadia Center; (2) Associated Industries of Massachusetts ("AIM"); (3) the City of Cambridge ("Cambridge"); (4) the towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Edgartown, Eastham, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, West Tisbury, Wellfleet, and Yarmouth, as well as Barnstable County and Dukes County, acting together as the Cape Light Compact (collectively, "Cape Light Compact"); (5) Conservation Law Foundation ("CLF"); (6) Department of Energy Resources ("DOER"); (7) the Federal Executive Agencies ("FEA"); (8) Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association ("Low Income Network"); (9) Northeast Clean Energy Council ("NECEC"); (10) Retail Energy Supply Association ("RESA"); (11) The Energy Consortium ("TEC"); (12) University of Massachusetts ("UMass"); and (13) Western Massachusetts Industrial Group ("WMIG").

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2 For a complete procedural history of this proceeding, refer to the D.P.U. 17-05 Order at 5-11.

The following entities were granted limited intervenor status: (1) the Town of Barnstable ("Barnstable"); (2) Cape and Vineyard Electric Cooperative ("CVEC"); (3) ChargePoint, Inc. ("ChargePoint"); (4) Choice Energy, LLC ("Choice Energy"); (5) Direct Energy Business, LLC, Direct Energy Business Marketing, LLC, Direct Energy Services, LLC, and Direct Energy Solar, LLC (collectively, as "Direct Energy"); (6) the Energy Consumers Alliance of New England, Inc., d/b/a Massachusetts Energy Consumers Alliance ("Mass. Energy") and the Sierra Club; (7) the City of Newton and the Towns of Arlington, Lexington, Natick and Weston ("Municipalities"); (8) PowerOptions, Inc. ("PowerOptions"); (9) Sunrun, Inc. ("Sunrun") and the Energy Freedom Coalition of America, LLC ("EFCA"); and (10) Vote Solar.[3] Finally, the following entities were granted limited participant status: (1) The Berkshire Gas Company; (2) Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; (3) the Massachusetts Water Resources Authority; (4) Microgrid Resources Coalition; (5) the Union of Concerned Scientists; and (6) Wal-Mart Stores East, LP.

III. OVERVIEW OF COMPANIES RATE DESIGN PROPOSALS

The Companies' initial filing included a number of rate design proposals, including the elimination of separate rates for NSTAR Electric's three operating units (i.e., Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company) and the establishment of one rate for each rate class; the consolidation and

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3 Regarding intervention and limited intervention, see D.P.U. 17-05, Hearing Officer Ruling on Petitions for Intervention at 6-8 (July 17, 2017); D.P.U. 17-05, Hearing Officer Ruling on Petitions for Intervention at 5-9 (March 13, 2017).

alignment of NSTAR Electric's and WMECo's general service rate classes; the consolidation of a number of reconciling mechanism rates; the introduction of a new optional time-of-use rate (rate G-5) for certain small general service (rate G-1) customers; and the implementation of a monthly minimum reliability contribution ("MMRC") rate for new customers seeking to install distributed generation. In their initial filing, the Companies did not propose to consolidate the distribution rates of NSTAR Electric and WMECo. Further, in the initial filing, pursuant to Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A (2008), Eversource proposed to implement a rate mechanism to decouple NSTAR Electric's electric revenues from its sales.

On June 1, 2017, the Companies filed a revised rate design proposal that contained several key differences from the Companies' initial filing. In particular, the Companies proposed to: (1) consolidate the revenue requirements of NSTAR Electric and WMECo for rates effective January 1, 2018 and January 1, 2019; (2) maintain existing rate classes, using legacy cost allocation studies, for rates effective January 1, 2018; (3) consolidate rate classes and rates for NSTAR Electric's and WMECo's residential customers effective January 1, 2019; (4) retain rate class WR in 2019; and (5) modify the proposed transmission revenue allocation and rate design, the low-income discount, and certain components of the MMRC rate.

The Companies initially requested that any new rates approved in this proceeding be implemented in two phases, with the first phase to take effect on January 1, 2018, and the second phase to take effect on January 1, 2019 (see Exh. ES-RDP-1, at 48-49, 51, 63). On

December 8, 2017, Eversource filed a Motion to Delay Implementation of Base Distribution Rates ("Motion to Delay Rate Implementation"). In the Motion, the Companies request that the new rates approved in the D.P.U. 17-05 Order for effect on January 1, 2018, instead be implemented on February 1, 2018, with no retroactive impact (Motion at 2). After opportunity for comment from the parties, the Department stamp-approved the Motion on December 14, 2017. Accordingly, the Companies' currently effective distribution rates and tariffs shall remain in place until February 1, 2018, unless otherwise ordered by the Department. Further, the Department will consider any rate design proposals and proposed tariffs initially proposed by the Companies for effect on January 1, 2018, to be proposed for effect on February 1, 2018.

IV. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 383 (2016); Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 294 (2016); Bay State Gas Company, D.P.U. 13-75, at 330 (2014); Bay State Gas Company, D.P.U. 12-25, at 444 (2012); New England Gas Company, D.P.U. 10-114, at 341 (2011).

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest cost means for society as a whole. Thus, efficiency in rate structure means that it is cost based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 15-155, at 383; D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 13-75, at 330; D.P.U. 12-25, at 445; D.P.U. 10-114, at 342.

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.P.U. 15-155, at 384; D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 13-75, at 331; D.P.U. 12-25, at 444-445; D.P.U. 10-114, at 342.

There are two steps in determining rate structure: cost allocation and rate design. Cost allocation assigns a portion of a company's total costs to each rate class through an embedded allocated cost of service study ("ACOSS"). The allocated cost of service represents the cost of serving each rate class at equalized rates of return given the company's level of total costs.

D.P.U. 15-155, at 384; D.P.U. 15-80/D.P.U. 15-81, at 296; D.P.U. 13-75, at 331; D.P.U. 12-25, at 446; D.P.U. 10-114, at 342.

There are four steps to develop an ACOSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based on the cost groupings and allocators chosen and then to sum for each rate class the costs allocated in order to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 15-155, at 384-385; D.P.U. 15-80/D.P.U. 15-81, at 296; D.P.U. 13-75, at 332; D.P.U. 12-25, at 446-447.

The results of the ACOSS are compared to the revenues collected from each rate class in the test year. If these amounts are reasonably comparable, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of the return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 15-155, at 385; D.P.U. 15-80/D.P.U. 15-81, at 297; D.P.U. 13-75, at 332; D.P.U. 12-25, at 446.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an ACOSS, but also explicitly considers the effect of its rate structure decisions on the amount customers are billed. For instance, the pace at which fully cost-based rates are implemented depends, in part, on the effect of the changes on customers. In addition, considering the goals of efficiency and fairness, the Department has also ordered the establishment of special rate classes for certain low-income customers and considers the effect of such rates and rate changes on low-income customers. D.P.U. 15-155, at 385; D.P.U. 15-80/D.P.U. 15-81, at 297; D.P.U. 13-75, at 332; D.P.U. 12-25, at 447. To reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another class unless a clear record exists to support such subsidies — or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(i). In addition, G.L. c. 164, § 94I ("Section 94I") requires the Department, in each base distribution rate proceeding, to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent.[4]

[4] An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, Section 20, inserted Section 94I:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 94, the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any [one] customer class would be more than [ten] percent, the [D]epartment shall phase in the elimination of any cross

The Department reaffirms its rate structure goals that are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 15-155, at 386; D.P.U. 15-80/D.P.U. 15-81, at 298; D.P.U. 13-75, at 333; D.P.U. 12-25, at 447.

The second step in determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The overarching requirement for rate design is that a given rate class should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above. D.P.U. 15-155, at 386; D.P.U. 15-80/D.P.U. 15-81, at 298; D.P.U. 13-75, at 333; D.P.U. 12-25, at 447. Further, G.L. c. 164, § 141 ("Section 141") provides:

> In all decisions or actions regarding rate designs, the department shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount.

B. Marginal Cost study

1. Introduction

Marginal cost is a measure of the additional cost that a firm incurs to provide an additional unit of a good or service (Exh. ES-MCOS-1, at 3). It is a well-established

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subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

principle in economic theory that the best allocation of resources will occur in an economy where prices of goods are set at the marginal cost (Exh. ES-MCOS-1, at 3).

2. Companies Proposal

The Companies submitted a combined marginal cost of service study ("MCS") on behalf of the NSTAR Electric legacy companies (i.e., Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company) and WMECo (Exhs. ES-MCOS-1, at 1-18; ES-MCOS-2, Schs. MCOS-1 through MCOS-5). The MCS concluded that the marginal cost per-kilowatt ("kW") increase in demand for a primary distribution customer is \$50.41, and for a secondary distribution customer is \$71.18 (Exhs. ES-MCOS-1, at 2, 16; ES-MCOS-2, Sch. MCOS-5, at 2).

To prepare the MCS, the Companies first calculated Eversource's marginal distribution capacity costs by regressing the total cost of capacity-related plant additions on electricity demand for its primary and secondary systems (Exh. ES-MCOS-2, Sch. MCOS-1). The Companies loaded this amount to incorporate general plant and then levelized using a fixed carrying charge rate of 8.08 percent (Exh. ES-MCOS-2, Sch. MCOS-5, at 1). The levelized, annualized cost of marginal plant investment was determined to be \$8,326.01 and \$9,140.61 for Eversource's primary and secondary systems, respectively (Exh. ES-MCOS-2, Sch. MCOS-5, at 1).

Eversource then calculated the Companies' marginal operations and maintenance ("O&M") expenses (Exh. ES-MCOS-2, Sch. MCOS-2). Specifically, Eversource regressed O&M expenses separately on peak demand (Exh. ES-MCOS-2, Sch. MCOS-2). The

Companies added together these two evaluations to get primary and secondary total marginal O&M expense (Exh. ES-MCOS-2, Sch. MCOS-5, at 1). For Eversource's primary system, the total marginal O&M expense was $35,716.54 and for Eversource's secondary system the total marginal O&M expense was $5,582.09 (Exh. ES-MCOS-2, Sch. MCOS-5, at 1).

Next, Eversource estimated the Companies' total administrative and general ("A&G") expenses (Exh. ES-MCOS-2, Sch. MCOS-3, at 1). Eversource estimated the amounts by first regressing A&G expenses on utility plant and O&M expense (Exh. ES-MCOS-2, Sch. MCOS-3, at 1). The resulting coefficients suggested that A&G was approximately 0.50 percent of the Companies' plant additions and 6.47 percent of the Companies' O&M expense (Exh. ES-MCOS-2, Sch. MCOS-3, at 1). Accordingly, Eversource multiplied its previous evaluations of marginal plant additions and marginal O&M expenses by 0.50 percent and 6.47 percent, respectively (Exh. ES-MCOS-2, Sch. MCOS-5, at 1). Total A&G expenses were determined to be $2,832.39 and $932.63 for Eversource's primary and secondary system, respectively (Exh. ES-MCOS-2, Sch. MCOS-5, at 1).

The final task of the MCS was to determine the revenue requirement for Eversource's working capital. For this calculation, Eversource first regressed the Companies' materials and supplies expense ("M&S") on total utility plant to determine their relationship (Exh. ES-MCOS-2, Sch. MCOS-4, at 4). The results revealed that marginal M&S per dollar of marginal plant investment was approximately 0.49 percent (Exh. ES-MCOS-2, Sch. MCOS-4, at 4). Thus, Eversource multiplied the Companies' assessment of total marginal plant investment by the 0.49 percent to calculate the M&S cost (Exh. ES-MCOS-2, Sch. MCOS-5, at 1). Next, Eversource estimated the Companies' cash working capital O&M allowance by multiplying their total marginal O&M expense by 9.123 percent, the cash working capital allowance rate (Exh. ES-MCOS-2, Sch. MCOS-5, at 1). The sum of the M&S cost and the Companies' cash working capital O&M allowance was then multiplied by the effective tax rate (11.40 percent) to arrive at the final assessment for working capital (Exhs. ES-MCOS-2, Schs. MCOS-4, at 4, MCOS-5, at 1; DPU-34-7). The revenue requirement for working capital totaled $429.25 for Eversource's primary system, and $121.36 for its secondary system (Exh. ES-MCOS-2, Sch. MCOS-5, at 1).

The Companies then added together its assessments of marginal plant, marginal O&M expense, marginal A&G expenses, and marginal revenue requirement for working capital to calculate the total marginal cost-per-megawatt for Eversource's primary system of $47,304 and cost-per-megawatt for Eversource's secondary system of $15,777 (Exh. ES-MCOS-2, Sch. MCOS-5, at 1).[5] This sum was increased by 4.87 percent to reflect the rate year inflation rate (Exh. ES-MCOS-2, Schs. MCOS-3, at 1, MCOS-4, at 4). It was then multiplied by the ratio of the transmission and distribution demand loss factors to arrive at the MCS's final assessment that the marginal cost per-kW increase in demand for a primary distribution customer is $50.41, and for a secondary distribution customer is $71.18

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5 For Eversource's primary system, the sum of marginal plant ($8,326), marginal O&M expense ($35,717), marginal A&G expenses ($2,832), and marginal revenue requirement for working capital ($429) is $47,304. For Eversource's secondary system, the sum of marginal plant ($9,141), marginal O&M expense ($5,582), marginal A&G expenses ($933), and marginal revenue requirement for working capital ($121) is $15,777.

(Exhs. ES-MCOS-1, at 2, 16; ES-MCOS-2, Schs. MCOS-3, at 2, MCOS-5, at 2). No party addressed the Companies' MCS on brief.

3. Analysis and Findings

In Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 243-244, in determining marginal costs, we directed companies to use multiple variable regression equations when regressing historical plant investment on customer load without differentiating among customer classes. We also directed companies to test for multicollinearity, heteroscedasticity, and autocorrelation, and apply remedial procedures as necessary. In addition, we required that companies perform a check of theoretical consistency. D.T.E. 02-24/25, at 243-244. The Department has reviewed the Companies' proposal and finds that it is in compliance with these directives (Exhs. ES-MCOS-2, Schs. MCOS-1, at 1-2, MCOS-2, at 1-4, MCOS-3, at 1-3; DPU-4-9; DPU-4-11; Tr. 17, at 3524-3525).

Further, in D.T.E. 02-24/25, at 243, the Department directed that all historical (time series) data sets used in preparing a MCS must be no less than 30 years in length in order to improve the accuracy of the econometric analyses. Eversource acknowledges that it did not provide 30 years of historical data in support of its MCS (Exh. ES-MCOS-1, at 4, 5, and 7). The Companies state that reliable data was not available prior to 1991 for the NSTAR Electric legacy companies and, therefore, only 25 years of data was available for the MCS analysis (Exh. ES-MCOS-1, at 4, 5, and 7). The Department accepts Eversource's representation regarding the lack of reliable NSTAR Electric-related data prior to 1991. The Department finds that, in this instance, given the difficulties in obtaining sufficient data, the use of 25 years of reliable historical data is acceptable for preparing the MCS. See New England Gas Company, D.P.U. 08-35, at 230 (2009) (Department accepted less than 30 years of historical data due to difficulties in obtaining data over a 30-year period). Our decision, however, is not a departure from the Department's long-standing requirement for distribution companies to provide 30 years of reliable historical data. Rather, it is in recognition of the circumstances present in this particular case.

Next, we find that, consistent with Department precedent the Companies have removed all production, transmission, and customer costs from the MCS (Exhs. ES-MCOS-1, at 4; DPU-4-1; DPU-4-8, Att.; DPU-4-9, Att.). Bay State Gas Company, D.T.E. 05-27, at 322 & n.170 (2005).

Finally, the Department has cautioned that the extensive use of dummy variables and autoregressive terms in a regression analysis may not lead to the development of a model with the best predictive powers. D.P.U. 10-114, at 355. In the past, the Department directed the former New England Gas Company to develop a marginal cost study that limits the number of dummy variables and autoregressive terms or, alternatively, to provide justification as to why the company was unable to identify causal variables. D.P.U. 10-114, at 355. While the record in the instant case indicates that Eversource also used a majority of dummy variables and autoregressive terms, the Department is satisfied with the Companies' explanation for their use and, as such, accepts their results (Exhs. DPU-4-10, Att.; RR-DPU-53). However, we reiterate our concern regarding the extensive use of dummy variables and autoregressive terms. Therefore, we find it appropriate to extend the directive made in D.P.U. 10-114 to all electric and gas companies. Accordingly, going forward, the Department directs all electric and gas companies to limit the number of dummy variables and autoregressive terms or, alternatively, provide justification as to why the company was unable to identify causal variables.

C. Allocated Cost of Service Study

1. Introduction

Eversource performed multiple ACOSSs[6] that directly assign or allocate, based on cost-causation principles, the Companies' total cost of service to each rate class (Exh. ES-ACOS-1, at 3). Generally, there are three steps to the development of the Companies' ACOSS (Exh. ES-ACOS-1, at 4).

First, the Companies functionalized costs by operational function such as distribution or transmission (Exh. ES-ACOS-1, at 4, 6-7). Eversource proposed that all costs be functionalized as distribution-related because this function captures all the costs that it proposes to recover through base distribution rates (Exh. ES-ACOS-1, at 6-7).

Second, the Companies classified functionalized costs as demand-, energy-, customer-, or streetlight-related according to the system design or operating characteristics that cause them to be incurred (Exh. ES-ACOS-1, at 4). Demand-related costs are associated with plant that is designed, constructed, and operated to meet peak demand requirements that customers impose on the system (Exh. ES-ACOS-1, at 5). Energy-related costs vary with the electricity consumed by customers (Exh. ES-ACOS-1, at 5). Customer-related costs are a function of

6 This section addresses the Companies' proposed design of their ACOSS. The use of multiple ACOSS will be discussed separately in Section IV.D.2 below.

the number of customers Eversource serves, and the Companies incur these costs whether or not the customer has consumption (Exh. ES-ACOS-1, at 4). Customer-related costs may include capital costs associated with services and meters, customer service expenses, and accounting expenses (Exh. ES-ACOS-1, at 4). The Companies used the streetlight classification to isolate the costs of Companies-owned street and area lighting facilities for the rate design (Exh. ES-ACOS-1, at 7).

Regarding the classification of specific cost accounts, the Companies proposed to classify 100 percent of the costs in account 303 (intangible plant) and account 904 (uncollectibles) as customer-related (Exhs. ES-ACOS-1, at 10; ES-ACOS-3, at 2, AG-13-8; Tr. 16, at 3282). Additionally, Eversource proposed to classify administrative and general costs using plant or labor internal allocation factors, and general plant costs using the internal labor allocation factor, which result in a portion of these costs classified as customer-related and a portion of these costs classified as demand-related (Exh. ES-ACOS-1, at 10-11). Finally, the Companies proposed to classify 100 percent of costs in accounts 364, 365, 367 (poles and conductors) as demand-related (Exh. ES-ACOS-3, at 1).

The third step is the allocation of each functionalized and classified cost element to each rate class based on cost-causation principles (Exh. ES-ACOS-1, at 5).[7] Eversource proposed to either directly assign or allocate costs to rate classes using internal or external

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7 Inherent in this third step is the process of identifying an allocator that is most appropriate for costs in each classification within each function.

allocators (Exh. ES-ACOS-1, at 5).[8] Direct assignment of costs can be accomplished with specific identification and isolation of plant and/or expenses that are incurred exclusively to serve a specific customer or group of customers and best reflect cost-causative characteristics (Exh. ES-ACOS-1, at 5). Eversource calculated external allocation factors, such as sales, number of customers, or peak demands, from their records (Exh. ES-ACOS-1, at 5). The Companies developed internal allocation factors within the ACOSS from previously allocated costs (e.g., using allocated plant costs to allocate depreciation expenses) (Exh. ES-ACOS-1, at 5). Eversource proposed to allocate costs for line transformers in account 368 using the sum of customer non-coincident peak (i.e., the maximum demand of each customer at any time during the year) (Exh. ES-ACOS-1, at 9).

2. Positions of the Parties

a. Attorney General

According to the Attorney General, the Companies committed two errors in the design of their ACOSS (Attorney General Brief at 8).[9] The Attorney General argues that the Companies improperly: (1) classified the account for miscellaneous intangible plant, or

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8 Internal allocation factors are developed from previously allocated costs (Exh. ES-ACOS-1, at 5). External allocation factors are developed from the Companies' records (Exh. ES-ACOS-1, at 5).

9 Unless otherwise specifically noted, all citations to the briefs in this Order refer to the briefs filed pursuant to the rate design track established by the Department on June 19, 2017. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, Hearing Officer Memorandum, Procedural Schedule – Rate Design Track (June 19, 2017).

account 303; and (2) allocated the account for line transformers, or account 368 (Attorney General Brief at 8-9).

The Attorney General explains that account 303 contains the costs of capitalized computer software licenses (Attorney General Brief at 8). According to her review of the specific software licenses that the Companies recorded to account 303, the Attorney General alleges that the software services multiple functions, such as meeting demand, enabling the provision of energy, typical customer service functions, outage management, plant accounting, geographic information systems, and workforce management (Attorney General Brief at 8, citing Tr. 16, at 3282-3284). The Attorney General contends that when an account services multiple functions, it is customary to use an allocator that includes a proportion of costs from all functions, such as a labor or total plant allocator (Attorney General Brief at 8). However, she maintains that the Companies instead assigned 100 percent of the costs in account 303 to the customer function (Attorney General Brief at 8). The Attorney General contends that this method results in excessive costs of these investments allocated to residential customers (Attorney General Brief at 8). Therefore, the Attorney General recommends classifying the costs in account 303 using a labor allocator (Attorney General Brief at 9, citing Exh. AG-SJR-1, at 12-13).

In allocating costs from account 368, the Attorney General argues that the Companies failed to recognize the diversity in demand from customers that are served by the same transformer (Attorney General Brief at 9). The Attorney General maintains that it is appropriate to use an allocation factor that recognizes diversity of demand within a rate class because several customers sharing a transformer do not peak at the same time (Attorney General Brief at 9, citing Exh. AG-SJR-1, at 14-16). The Attorney General argues that the Companies method of using a customer non-coincident peak demand (or the maximum demand of each customer at any time during the year) derived from a load research study, does not consider customer diversity (Attorney General Brief at 9-10, citing Tr. 16, at 3276). Accordingly, the Attorney General asserts that the allocation of account 368 for line transformers should use a method that recognizes customer peak diversity (Attorney General Brief at 10, citing Exh. AG-SJR-1, at 14-16).

b. Acadia Center

Acadia Center argues that in several ways the Companies improperly allocated certain costs as to overstate customer-related costs (Acadia Center Brief at 11). Thus, Acadia Center requests that the Department direct Eversource to update its ACOSS to properly allocate customer-related costs (Acadia Center Brief at 11). According to Acadia Center, this will ensure that customer charges are no higher than the customer-related costs (Acadia Center Brief at 11).

First, Acadia Center agrees with the Attorney General that the Companies' proposed classification of costs in account 303 for intangible plant as customer-related is incorrect (Acadia Center Brief at 11, citing Exhs. AG-SJR-1, at 10-12; AC-ML-1, at 22). Acadia Center maintains that the functions performed by the software in account 303, which include geographic information systems ("GIS") and outage management software, are not 100 percent related to customer functions (Acadia Center Brief at 11, citing Exh. AG-13-8).

According to the Acadia Center, costs related to the separate functions of the software in account 303 should be separately allocated (Acadia Center Brief at 11, citing Exh. AC-ML-1, at 22).

Second, Acadia Center argues that the ACOSS treatment of all uncollectible expenses as customer-related is inappropriate (Acadia Center Brief at 12, citing Exh. AC-ML-1, at 23). According to Acadia Center, NSTAR Electric's residential rate classes are allocated approximately $10 million in customer-related O&M expenses from the Companies' proposed allocation method of uncollectible expenses (Acadia Center Brief at 12, citing Exh. DPU-1-8, Att. at 19).

Third, Acadia Center maintains that the Companies improperly classified other administrative and general expenses and general plant as customer-related (Acadia Center Brief at 12). Acadia Center argues that these categories of expenses do not represent customer-related O&M expenses directly incurred from metering, meter reads, customer accounts and record, and customer service (Acadia Center Brief at 12, citing Exh. AC-ML-1, at 23). Accordingly, Acadia Center recommends that the other administrative and general expenses and general plant accounts be allocated without any classification of these costs as customer-related because these accounts do not increase when the number of customer increases (Acadia Center Brief at 12, citing Tr. 18, at 3601). For all these reasons, Acadia Center maintains that too much of the cost in these accounts are classified as customer-related (Acadia Center Brief at 11-12).

c. FEA

FEA argues that the Companies' ACOSS is flawed because it does not account for the customer-related costs of poles and conductors (FEA Brief at 7). According to FEA, the Companies acknowledged that the distribution revenue requirement of plant beyond meters is both customer- and demand-related (FEA Brief at 7-8, citing Exh. ES-ACOS-1, at 15; Western Massachusetts Electric Company, D.P.U. 10-70 (2011), Exh. WM-EAD). Therefore, by classifying these costs as demand related, FEA maintains that the Companies' ACOSS overstates the cost of service for large users for 2019 rates, such as the legacy Rate G-3 customers in the Boston Edison Company service territory (FEA Brief at 7-8).

d. WMIG

WMIG disagrees with the Attorney General and argues that the Companies did not make any errors in its ACOSS (WMIG Reply Brief at 8, citing Attorney General Brief at 8). According to WMIG, allocating costs in account 303 using a customer allocator is reasonable because, WMIG contends, software systems (e.g., GIS and system control and data acquisition ("SCADA")) do not vary with demand (WMIG Reply Brief at 9, citing Tr. 16, at 3282). Therefore, WMIG asserts that the Department should reject the Attorney General's argument that costs in account 303 should be allocated using a labor or total plant allocator (WMIG Reply Brief at 9).

Moreover, WMIG objects to the Attorney General's argument that the Companies' allocation of line transformer costs in account 368 using non-coincident peak does not consider diversity of customers on a line (WMIG Reply Brief at 9). According to WMIG, coincident peaks are possible when residential customers return home in the late afternoon and turn on many household appliances and lights at the same time (WMIG Reply Brief at 9). WMIG maintains that the Companies are required to size their infrastructure to ensure customer demand can be served at any moment (WMIG Reply Brief at 9). Accordingly, WMIG argues that line transformers must be ready to accommodate demand (WMIG Reply Brief at 9). Therefore, WMIG alleges that the Companies' allocation of account 368 is reasonable (WMIG Reply Brief at 9).

Finally, WMIG argues that the result of implementing the Attorney General's recommendations would distort the ACOSS by benefitting residential customers at the expense of commercial customers (WMIG Reply Brief at 9-10). Therefore, WMIG asserts that the Department should reject the Attorney General's recommended changes to the ACOSS (WMIG Brief at 10).

e. Companies

i. Account 303

Eversource did not specifically address the aforementioned arguments on brief. However, according to the Companies, investments in account 303 serve multiple functions including outage management, SCADA, plant accounting, workforce management, customer information systems, GIS, meter reading, net metering, billing, and other functions (Exh. AG-13-8; Tr. 16, at 3282-3284). Further, the Companies assert that these costs are more customer-related than demand-related, and they assigned 100 percent of the costs in account 303 to the customer function (Exhs. ES-ACOS-1, at 10; AG-13-8; Tr. 16, at 3282).[10] According to Eversource, although the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual treats all intangible plant as demand-related, the Companies claim that this guidance is found in a discussion of production plant cost allocation, and therefore, does not apply here (Exhs. AG-13-8; DPU-1-7, Att. at 40).

ii. Account 368

The Companies used the sum of customer non-coincident peak demands, or the maximum demand of each customer at any time during the year, to allocate costs for line transformers in account 368 (Exh. ES-ACOS-1, at 9). According to the Companies, facilities closer to the customer have lower load diversity than facilities further from the customer (Exh. ES-ACOS-1, at 9). Therefore, Eversource states that facilities are sized to meet a higher demand level representative of non-coincident peak demand (Exh. ES-ACOS-1, at 9).

iii. Uncollectible Expenses

Eversource states that it classifies uncollectible expenses as customer-related (Exh. ES-ACOS-3, at 2). According to the Companies, they allocated uncollectible expenses in account 904 on the basis of write-offs (Exh. ES-ACOS-1, at 11).

iv. Other Administrative and General Plant Expenses

The Companies assert that they allocated administrative and general costs using plant or internal labor allocation factors (Exh. ES-ACOS-1, at 11). Eversource states it classified

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10 However, the Companies state that SCADA and GIS "could have a demand function to it, in terms of that they're used for design and operation of the system" (Tr. 16, at 3283).

and allocated general plant costs using the internal labor allocation factor based on the classification and allocation of labor expenses (Exh. ES-ACOS-1, at 10).

v. Poles and Conductors

The Companies state that they classified poles and conductors as demand-related (Exh. ES-ACOS-3, at 1). Eversource maintains that it allocated the cost of poles and conductors using the class non-coincident peak and class non-coincident peak secondary allocators (Exh. ES-ACOS-4, at 1).

3. Analysis and Findings

The Attorney General and Acacia Center disagree with the Companies' method of classifying costs in account 303 (Attorney General Brief at 8-9; Acadia Center Brief at 11). Further, the Attorney General argues that Eversource improperly allocated costs in account 368 (Attorney General Brief at 8-9). Conversely, WMIG disagrees with the Attorney General and argues that the Companies did not make any errors in its ACOSS (WMIG Reply Brief at 8). Moreover, Acadia Center contends that the Companies did not correctly classify uncollectible expenses, other administrative and general expenses, and general plant expenses (Acadia Center Brief at 12). Finally, FEA maintains that the Companies did not classify pole and conductor costs appropriately (FEA Brief at 7).

The Department has reviewed the types of software booked to account 303 and determines that it contains both customer- and demand-related software services (Exh. AG-13-7, Atts. (a) & (b)). The Companies' investments in account 303 serve multiple customer- and demand-related services including outage management, SCADA, plant accounting, workforce management, customer information systems, GIS, meter reading, net metering, and billing functions (Exh. AG-13-8; Tr. 16, at 3282-3284). Accordingly, the Department agrees with the Attorney General's position that account 303 would be more appropriately classified and allocated using the labor allocator. Moreover, WMECo used a labor allocator in its last base rate case to classify and allocate costs in account 303 (Exh. DPU-1-1, at 1). The Companies have not justified the change in classification and allocation method for account 303. Therefore, the Department directs Eversource to rerun its ACOSS using the labor allocator for account 303 in its compliance filing.

Regarding account 368, the non-coincident peak cost allocation method most accurately captures the drivers behind transformer costs. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 413 (2009). Eversource used the non-coincident peak method to allocate costs for transformers in account 368 (Exh. ES-ACOS-1, at 9). Here, the Attorney General recommends that the non-coincident peak allocation method should consider load diversity (Attorney General Brief at 9). The Attorney General relies on data from United Illuminating Company, a Connecticut-based utility, to calculate her proposed diversity factors for recalculating the non-coincident peak allocation factors that the Companies used to allocate transformers (Exh. AG-SJR-1, at 15-16). The record in this proceeding, however, is insufficient to determine Eversource-specific diversity factors to recalculate the allocation factors for transformers. Therefore, the Department allows Eversource's proposed allocation of transformers for account 368, and notes that we expect the Companies to address the allocation of transformer costs in a future proceeding. In this regard, the Department puts the Companies, and all electric distribution companies, on notice that we will consider the allocation of transformer costs using the non-coincident peak allocation method with the application of load diversity factors in each electric distribution company's next base distribution rate proceeding. Thus, as part of the initial filing in its next base distribution rate proceeding, each electric distribution company must address and provide justification for the continued use of the non-coincident peak allocation method without application of the load diversity factor in its proposed ACOSS.

Further, Acadia Center and FEA allege deficiencies in the Companies' ACOSS regarding the allocation of uncollectible, other administrative and general, general plant, poles, and/or conductor costs (Acadia Center Brief at 12; FEA Brief at 7). Eversource records the cost of uncollectibles to account 904. FERC accounts 901-917 contain costs that are customer-related costs because they include the costs of billing and collection, providing service information, and advertising (Exh. DPU-1-7, Att. at 108). Uncollectibles are related to the costs of billing and collection, and therefore, the Companies appropriately classified the costs as customer-related.

Moreover, Eversource classified and allocated administrative and general expenses using the plant or labor internal allocation factors, and general plant costs using the internal labor allocation factor (Exh. ES-ACOS-1, at 10-11). Acadia Center maintains that too much of the cost in these accounts are classified as customer-related (Acadia Center Brief at 12). Administrative and general expenses and general plant serve many functions. The internal labor factor is based on the classification and allocation of labor expenses (Exh. ES-ACOS-1, at 10). These methods result in some costs in these accounts being classified as demand-related and some as customer-related. An account that serves multiple functions is usually allocated using a factor (e.g., labor) that recognizes the mixed use of the account (Exh. AG-SJR-1, at 12). The labor allocator is based on wages and salaries incurred across the utility (Exh. AG-SJR-1, at 12). A utility incurs labor costs throughout its business and therefore, the labor allocator provides a representation of costs that serve multiple functions throughout the utility (Exh. AG-SJR-1, at 12). Moreover, the classification of poles and conductors in accounts 364, 365, and 367 as 100 percent demand-related is a reasonable method and that the Department has approved in recent rate cases. D.P.U. 15-155 (Exh. NG-PP-2(c) at 1); D.P.U. 10-70 (Exh. WM-EAD at 7-8)

Having reviewed these arguments, we are not persuaded that the Companies' ACOSS requires any further modification. Therefore, the Department declines to adopt Acadia Center and FEA's recommendations regarding the classification and allocation of the following costs: uncollectible, other administrative and general, general plant, poles, and conductors. Accordingly, we accept the Companies' ACOSS as proposed and with the aforementioned directive regarding the allocation of costs in account 303.

D. Rate Design and Cost Allocation, Consolidation, and Alignment

1. Introduction

NSTAR Electric was created when BEC Energy and Commonwealth Energy System merged on August 25, 1999, forming a new holding company, NSTAR, with three retail electric distribution company subsidiaries: Boston Edison Company; Cambridge Electric Light Company; and Commonwealth Electric Company (Exh. ES-RDP-1, at 5). BEC Energy/Commonwealth Energy System, D.T.E. 99-19 (1999) (as part of the merger transaction between the two holding companies, Department approved a rate plan for these three subsidiaries, in addition to approving a rate plan for Commonwealth Gas Company). These subsidiaries began operating under the brand name NSTAR Electric on November 1, 2000, but offered retail service under three different sets of tariffs and pricing (Exh. ES-RDP-1, at 5). On April 4, 2012, the Department approved the merger of the Companies' holding companies NSTAR and Northeast Utilities. NSTAR/Northeast Utilities Merger, D.P.U. 10-170 (2012).

In the D.P.U. 17-05 Order at 43-44, the Department approved the complete corporate consolidation of Eversource's operations for both NSTAR Electric and WMECo. In anticipation of this approval, in their initial filing, the Companies proposed a consolidation of the cost allocation for all of their customers across all four former subsidiaries (Exh. ES-RDP-1, at 5-6).[11] Further, the Companies proposed an alignment of the rate tariffs between the three NSTAR Electric companies and WMECo (Exh. ES-RDP-1, at 6).[12]

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11 The term "consolidation" in the context of the Companies' cost allocation proposal refers "to the process of condensing the number of tariffs or rate classes within NSTAR Electric and WMECo, respectively" (Exh. ES-RDP-1, at 8).

12 The term "alignment" in the context of the Companies' tariffs refers "to the process of standardizing the availability and applicability provisions for each rate class or tariff so that customers in [NSTAR Electric] and [WMECo] will be subject to a single set of rules" (Exh. ES-RDP-1, at 8).

The Companies stated that their alignment plan would simplify rate administration and establish a common platform to consolidate the pricing of rates of NSTAR Electric and WMECo in a future rate case filing (Exh. ES-RDP-1, at 6).

In their consolidation and alignment plan, the Companies proposed twelve tariffs that govern base distribution rate availability for both NSTAR Electric and WMECo for effect on January 1, 2019 (Exh. ES-RDP-1, at 9-10; RR-DPU-51, Att. (c) at 30-31). These twelve tariffs include: (1) Rate R-1, residential; (2) Rate R-2, residential low-income; (3) Rate R-3, residential heating; (4) Rate R-4, residential heating low-income; (5) Rate G-1, small general service;[13] (6) Rate G-5, optional time of use ("TOU") small general service; (7) Rate G-2, medium general service; (8) Rate G-3, large general service; (9) Rate G-4, extra-large general service; (10) Rate S-1, street and security lighting – company owned; (11) Rate S-2, street and security lighting - customer owned; and (12) Rate WR, Massachusetts Water Resource Authority (Exh. ES-RDP-1, at 9-10; RR-DPU-51, Att. (c) at 30-31). The Companies proposed the same distribution rates for residential customers across all legacy companies effective January 1, 2019, but Eversource proposed separate distribution rates for commercial and industrial ("C&I") customers between NSTAR Electric and WMECo effective January 1, 2019 (Exhs. ES-RDP-1, at 10; DPU-56-9, at 1 (Supp.)).

The Companies based their proposed rate design consolidation and alignment on four primary objectives: (1) eliminating obsolete legacy rate classes; (2) matching availability

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13 Eversource proposed a demand and non-demand Rate G-1 (RR-DPU-51, Att. (c) at 13-16). To qualify for the non-demand Rate G-1, a customer must take single-phase service not exceeding 100 amperes (RR-DPU-51, Att. (c) at 13).

provisions of residential and C&I tariffs; (3) establishing rate classifications that customers will understand and that would provide for fair, consistent pricing to similar customers; and (4) limiting the number of customers that will be assigned to a new rate class that is different from the customer's current classification (Exh. ES-RDP-1, at 22-23). The Companies proposed a revised rate design on June 1, 2017 for which they seek Department approval (Exhs. ES-RDP-Rebuttal-1, at 2 (May 20, 2017); DPU-56-9 (Supp.); Companies Brief at 28). The revised rate design retained the aforementioned proposals.

2. Specific Components of the Companies' Proposals

In its revised rate design, Eversource proposed that customers remain on their legacy rate classes during a transition period (i.e., calendar year 2018) (Exh. DPU-56-9, at 1 (Supp. 1)). The Companies proposed that the consolidated residential rate classes and aligned C&I rate classes take effect on January 1, 2019 (Exh. DPU-56-9, at 1 (Supp. 1)).

The Companies proposed to use a legacy rate class ACOSS to design 2018 distribution rates using a fully consolidated revenue requirement for both NSTAR Electric and WMECo (Exh. DPU-56-9, at 1 (Supp.); RR-DPU-49, Atts. (A)-(E)). Therefore, the Companies proposed four ACOSS (one for each subsidiary company) to inform their rate design in 2018 (Exh. DPU-56-9, at 1, 7 (Supp.); RR-DPU-49, Atts. (A)-(E)). For rates effective January 1, 2019, the Companies proposed to use one consolidated ACOSS to inform their rate design for 2019 (Exh. DPU-56-9, at 1 (Supp.); RR-DPU-49, Att. (J)). The results of the Companies' consolidated ACOSS show that, at present rates, Eversource is currently earning an overall return of 5.8 percent, and individual class returns vary between -1.57 percent for street lighting to 8.64 percent for Rate G-1 (RR-DPU-49, Att. (J) at Exh. ES-ACOS-2 (ALT1) at 1-2).[14] The following descriptions of the Companies' rate design proposals include components of their initial and revised proposals.

a. Residential Rate Design

In 2018, the Companies proposed to retain all existing residential rate classes and design rates based on the legacy ACOSS results (Exh. DPU-56-9, at 1 (Supp.)). In 2019, the Companies proposed to consolidate rate classes and distribution rates for both NSTAR Electric and WMECo, so that, within each rate class, all residential customers across Eversource's service territory would have the same rates (Exhs. DPU-56-9, at 1 (Supp.); ES-RDP-1, at 17-18; ES-RDP-9, at 27-28). Thus, the Companies proposed that the consolidated residential tariffs (i.e., Rate R-1 to Rate R-4) will govern residential customers that NSTAR Electric and WMECo serve (Exh. ES-RDP-9, at 26).

For NSTAR Electric, the Companies' proposal for effect on January 1, 2019 eliminates the following residential rate classes and transfers these customers to the proposed consolidated Rate R-1: (1) Boston Edison Company's Rate R-4, optional residential TOU; (2) Cambridge Electric Light Company's Rate R-5, optional residential TOU; (3) Commonwealth Electric Company's Rate R-5, controlled water heating; and (4) Commonwealth Electric Company's Rate R-6, optional residential TOU (Exh. ES-RDP-9, at 14-16, 27-28). Additionally, the Companies' proposal eliminates Cambridge Electric Light

[14] The Department approved an overall return of 7.33 percent for NSTAR Electric and 7.26 percent for WMECo. D.P.U. 17-05, at 770, 779.

Company's Rate R-6, optional residential space heating TOU and transfers these customers to their proposed consolidated Rate R-3 (Exh. ES-RDP-9, at 14-16, 27-28). Further, Boston Edison Company's residential low-income space heating customers who currently are assigned to legacy rate class Rate R-2 will be transferred to the equivalent proposed rate, consolidated Rate R-4 (Exh. ES-RDP-2, Sch. RDP-2 (East) at 1-2). Finally, the Companies propose to eliminate seasonally differentiated pricing[15] for residential customers served by the legacy Commonwealth Electric Company (Exh. ES-RDP-1, at 27).

Regarding WMECo's legacy residential rate classes for effect on January 1, 2019, the Companies propose to eliminate inclining block rates and to implement a flat volumetric rate for WMECo's proposed residential rates (Exh. ES-RDP-1, at 13). WMECo's current residential rate classes align with the Companies' proposed consolidated residential rate classes (Exh. ES-RDP-1, at 9).

b. C&I Rate Design

Eversource's current rate classes for C&I customers vary among the Companies' four subsidiary electric companies (Exh. ES-RDP-1, at 53). Boston Edison Company currently offers the following C&I rates: Rate G-1, Rate G-2, TOU Rate G-3, Optional TOU Rate T-1, and TOU Rate T-2 (Exh. ES-RDP-1, at 53). Cambridge Electric Light Company currently offers the following C&I rates: Rate G-0 (Non-Demand); Rate G-1, Large General TOU/Secondary Rate G-2; Large General TOU /13.8 kilovolt ("kV") Service Rate G-3;

15 Seasonal rate options are available for customers with seasonal load characteristics, where summer electricity use from June through September is greater than winter electricity use over the remaining eight months (Exh. ES-RDP-9, at 27).

Optional General TOU Rate G-4; Commercial Space Heating Rate G-5; and Optional General TOU (Non-Demand) Rate G-6 (Exh. ES-RDP-1, at 53). Commonwealth Electric Company currently offers the following C&I rates: General Rate G-1; Medium General Service TOU Rate G-2; Large General Service TOU Rate G-3; General Power Rate G-4; Commercial Space Heating Rate G-5; All Electric School Rate G-6; and Optional General TOU Rate G-7 (Exh. ES-RDP-1, at 53).[16] WMECo currently offers the following C&I rates: small TOU T-0; large primary service Rate T-2, primary Rate T-4; extra-large primary service TOU T-5; small Rate G-0, primary Rate G-2; optional church Rate 24; and optional controlled water heating Rate 23.[17]

Effective January 1, 2019, the Companies propose to reassign NSTAR Electric and WMECo C&I customers to new rate classifications according to the following characteristics:

16 See Section IV.K.5 for a discussion of standby rate classes.

17 The following rates are closed to new customers: WMECo Rate 23 and Rate 24; Cambridge Electric Light Company Rate G-5; and Commonwealth Electric Company Rate G-4, Rate G-5, and Rate G-6 (M.D.P.U. Nos. 1002W, 1003W; M.D.T.E. Nos. 235G, 333F, 334F, 335F).

Consolidated C&I Rate Classes[18]

Consolidated / Aligned Rate Classification		Maximum Monthly Demand	
		Lower Limit	Upper Limit
Rate G-1 Non-demand	Small (Non-demand)	0 kW	N/A
Rate G-1 Demand	Small (Demand)	0 kW	≤ 100 kW
Rate G-2	Medium	> 100 kW	< 350 kW
Rate G-3	Large	≥ 350 kW	< 2,500 kW
Rate G-4	Extra Large	≥2,500 kW	

The Companies mapped customers from their current legacy rate classification to their new rate classification by using 2015 monthly billing data[19] ("billing database") for each customer by rate class, separately for Boston Edison, Cambridge Electric Light, Commonwealth Electric, and WMECo (Exh. ES-RDP-1, at 54-55). Based on the 2015 monthly billing determinants and the new rate class parameters, the Companies tallied the 2015 subtotals of each customer's billing determinant by each combination of current rate class and new rate class (Exh. ES-RDP-1, at 56). Based on this mapping, the Companies calculated a percent allocation of each billing determinant from the legacy rate classes to each new rate class ("Mapping Allocation Factors") (Exh. ES-RDP-1, at 56).

The Companies multiplied calendarized monthly test year billing determinants for the legacy rate classes by the Mapping Allocation Factors (Exh. ES-RDP-1, at 57). The product of the adjusted test year billing determinants and the Mapping Allocation Factors produced

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18 Source: Exh. ES-RDP-1, at 54.

19 Monthly billing data includes: customer identification code, customer meter code, current rate class, new rate class, if a bill was rendered, meter read dates, billed energy usage (kWh), including on and off peak energy usage; billing demand, including on- and off-peak billing demand (kW and/or kVa) (Exh. ES-RDP-1, at 56).

the Companies' test year billing determinants by the new rate classes (Exh. ES-RDP-1, at 57). Using the calculated billing determinants for the new rate classes, the Companies then calculated test year distribution revenues for each combination of legacy to proposed rate classification (e.g., legacy Boston Edison Company Rate G-1 (demand) to proposed consolidated Rate G-1 (demand)) (Exh. ES-RDP-1, at 57).

According to the Companies, their proposal does not assign all customers from a specific legacy rate class to the same proposed consolidated rate class (Exh. ES-RDP-1, at 58). The table below shows the number of legacy rate classes that move into a proposed consolidated rate class.

Legacy and Consolidated Rate Classes[20]

Legacy Service Area	G-1 (Non-Demand)	G-1 (Demand)	G-2	G-3	G-4
Boston Edison	3	6	3	3	2
Cambridge Electric Light	3	6	4	4	1
Commonwealth Electric	3	9	9	5	1
WMECo	2	6	5	4	1
Total	11	27	21	16	5

The Companies proposed separate rates between NSTAR Electric's and WMECo's C&I rate classes, although the proposed distribution rates are based on a shared revenue requirement (Exh. DPU-56-9, at 1 (Supp.)). The Companies state that the revised rate

20 Source: Exh. ES-RDP-1, at 59.

design generally results in lower costs assigned to WMECo's C&I customers (Exh. DPU-56-9, at 5 (Supp.)).

i. Mitigation Proposal

Based on a bill impact analysis, the Companies proposed to phase-in the new consolidated C&I distribution rates annually over five years with a plan that, the Companies state, is designed to minimize bill impacts for the largest number of customers (Exhs. ES-RDP-1, at 62; DPU-63-6, at 5 (Supp. 1)). The Companies' proposal includes several components.

Based on the Companies' proposed distribution rate design, the Companies evaluated total bill impacts to determine whether the overall levels and patterns of bill impacts to some of the legacy rate class groups of customers moving to a new, consolidated rate class were consistent with the Department's rate design principle of continuity (Exh. ES-RDP-1, at 64). The Companies identified approaches to reduce bill impacts for those legacy rate classes with bill impacts contravening this principle (Exh. ES-RDP-1, at 64). For these "mitigation-designated" legacy rate classes, the Companies determined rules and specific measures to subsidize the bills of these customers from other customers within the same rate class (Exhs. ES-RDP-1, at 64, 69-71).

Eversource proposed three mitigation strategies: (1) targeted discount; (2) two-part rate; and (3) TOU Rate G-5 (Exh. DPU-63-6, at 4-7 (Supp. 1)). The Companies proposed to set a 15-percent bill impact threshold to the extent the annual bill increase is greater than or equal to $360, or at a bill impact percentage that results in a $360 annual increase, whichever is greater, as the initial determinant of whether the legacy rate class grouping moving to a new, consolidated rate class would receive a subsidy (Exh. DPU-63-6, at 1 & n.2 (Supp. 1)).

The targeted discount strategy sought to cap the annual increases in total bills to customers in these legacy rate classifications during the phase-in period[21] at 15 percent or $360 per year, whichever is greater (Exh. DPU-63-6, at 4-5 (Supp. 1)). Eversource proposed to apply the targeted discount only to customers in a designated legacy rate class that would experience an increase more than the mitigation threshold (Exh. DPU-63-6, at 5 (Supp. 1)).

The Companies proposed the two-part rate mitigation approach to address bill impacts for NSTAR Electric legacy rate classes that they proposed to move into aligned Rate G-1 demand (Exh. DPU-63-6, at 6 (Supp. 1)). The proposed two-part rate includes only a customer charge and an energy charge, as opposed to Eversource's proposed Rate G-1 demand, which is a three-part rate and includes a demand charge (Exh. DPU-63-6, Att. (n) at 1 (Supp. 1)). Eversource proposes to make the optional two-part rate available only to customers taking service under legacy Cambridge Electric Light Company Rate G-0 and Rate G-5; and Commonwealth Electric Company Rate G-1, Rate G-1 Seasonal, and Rate G-4 (Exh. DPU-63-6, at 6 (Supp. 1)). Under the Companies' proposal, these customers may elect to be billed on either the NSTAR Electric aligned Rate G-1 demand or the two-part rate

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21 The phase-in period may last up to five years, depending on the legacy rate class receiving the subsidy (Exh. DPU-63-6, at 5 (Supp. 1)).

(Exh. DPU-63-6, at 6 (Supp. 1)). Eversource states that it will determine, on an initial basis, which rate class option is optimal for each customer (Exh. DPU-63-6, at 6 (Supp. 1)).

Eversource proposed a third mitigation option for Boston Edison Company legacy Rate G-2 (Municipal) and Commonwealth Electric Company Rate G-7 customers that it proposed to transfer to NSTAR Electric's aligned Rate G-1 demand (Exh. DPU-63-6, at 7 (Supp. 1)). The Companies determined that these customers would be best served under the proposed optional TOU Rate G-5 (Exh. DPU-63-6, at 7 (Supp. 1)).

The Companies proposed to work closely with any customer that cannot avoid significant bill impacts through any of the Companies' mitigation strategies caused by the Companies' rate consolidation and alignment proposal (Exh. DPU-63-6, at 13-14 (Supp. 1)).

c. Bill Impacts

Eversource calculated bill impacts by capping the total proposed revenue increase at ten percent of total revenue for each rate class (Exh. ES-RDP-1, at 39). The Companies calculated total revenue at current rates under consolidated base distribution rates and pro forma reconciling and Basic Service rates (Exh. ES-RDP-1, at 39). Eversource imputed energy supply prices for customers on alternate supply using the Basic Service rate (Exh. ES-RDP-1, at 39). The Companies re-allocated total revenue for each rate class above the cap to all other rate classes that did not exceed the ten percent threshold test based on the rate class share of proposed base distribution revenue at equal rates of return (Exh. ES-RDP-1, at 39). Eversource re-evaluated the new revenue targets to determine if the ten percent threshold test had been met (Exh. ES-RDP-1, at 39). Moreover, Eversource calculated the current, pro forma reconciling adjustment and Basic Service revenues using rates effective as of January 1, 2017 (Exh. ES-RDP-1, at 40). The Companies stated that test year pro forma revenue allows for the reflection of the proposed revenue increases taking place in the pension, storm, property tax, and basic service cost adjustment mechanisms (Exh. ES-RDP-1, at 40).

3. Attorney General's Proposal

The Attorney General proposed a rate design based on the results of a modified ACOSS used to set rate class revenue targets (Exh. AG-SJR-1, at 18). The Attorney General proposed to move residential rates towards a common customer charge, but to limit the increases to residential customer charges to no more than 1.5 times or no less than 0.5 times the class average increase (Exhs. AG-SJR-1, at 23; AG-SJR–AS-1, at 7).

The Attorney General proposed to retain the legacy C&I rate classes (Exh. AG-SJR-1, at 41). The proposal specifies that each rate component is increased by the same percentage as the revenue requirement increase for that legacy rate class (Exhs. AG-SJR-1, at 41; AG-SJR-AS-1, at 6; DPU-AG-1-7).

4. Positions of the Parties

a. Attorney General

i. Initial and Revised Proposals

The Attorney General maintains that both the Companies' initial and revised proposals do not meet the Department's rate continuity principle because Eversource has not demonstrated that its rate design changes are gradual and allow for customers to adjust to the new structures (Attorney General Reply Brief at 2, citing Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 7, n.5 (2001)). Instead, the Attorney General contends that Eversource proposed "a radical redesign" of its rates that included "dramatic" increases to customer charges, both increases and decreases to consumption charges, and new demand charges for some customers (Attorney General Reply Brief at 2).

According to the Attorney General, the Companies' initial rate design proposal does not meet the Department's rate design goals and was intended to meet the Companies' goal of easier administration of their rate schedules (Attorney General Brief at 10). The Attorney General claims that Eversource gave no weight to the impact that its rate design proposal had on residential customers (Attorney General Brief at 10). For example, the Attorney General asserts that the Companies have not justified their proposed 115-percent increase in the customer charge to Commonwealth Electric or the proposed 33-percent increase in the volumetric charge to Cambridge Electric Light, when, at the same time, Eversource proposed to increase total residential distribution revenues by only 14.5 percent (Attorney General Brief at 11). Further, the Attorney General asserts that the Companies' proposal is unreasonable because 88 percent of the proposed revenue increase to the R-1 rate class for Commonwealth Electric comes from increasing the customer charge (Attorney General Brief at 12). Therefore, the Attorney General maintains that approximately 100,000 residential customers will experience bill impacts outside a reasonable range (Attorney General Brief at 12, citing Exh. AG-SJR-1, at 17). According to the Attorney General, the Companies' proposal to consolidate NSTAR Electric's and WMECo's residential Rate R-1 and Rate R-2 caused these increases (Attorney General Brief at 12, citing Exh. AG-SJR-1, at 25). The Attorney General maintains that the Companies have not demonstrated that customer costs are the primary reason for the proposed rate increase (Attorney General Brief at 12, citing Exh. AG-SJR-1, at 27).

Regarding C&I customers, the Attorney General argues that the Companies' initial proposal contravenes the Department's fairness goal (Attorney General Brief at 13). The Attorney General alleges that of Eversource's 165,000 non-residential customers, approximately 105,000 would pay the same or less than their current distribution rates (Attorney General Brief at 13). Therefore, the Attorney General maintains that it is unfair to burden only 60,000 C&I customers with the cost of the entire increase (Attorney General Brief at 13). Further, the Attorney General argues that increases to those 60,000 customers range from a few percent to more than double (Attorney General Brief at 13, citing Exh. AG-SJR-1, at 39). Moreover, the Attorney General argues that the entire burden of WMECo's revenue increase falls onto 7,000 of WMECo's 17,000 C&I customers (Attorney General Brief at 13).

The Attorney General contends that a rate design proposal does not make sense that causes: (1) customers' bills to increase by 25 percent or more in a rate class where revenues are decreasing: (2) bills to decrease in a class where revenues are supposed to increase by up to 46 percent (Attorney General Brief at 14, citing Exh. AG-SJR-1, at 40). Therefore, the Attorney General recommends that the Department reject the Companies' initial rate design proposal (Attorney General Brief at 14).

The Attorney General contends that the Companies' revised rate design proposal is not based on the cost to serve a customer class or service area and shifts more than $4 million from WMECo's customers to NSTAR Electric's customers (Attorney General Brief at 4, 14, citing Exh. AG-SJR-24; 14, 15; Attorney General Reply Brief at 3). Therefore, the Attorney General claims that the revised rate design is arbitrary and cannot be cost-based if the initial rate design proposal is cost-based (Attorney General Brief at 5, 14-15, citing Exh. AG-SJR-AS-1, at 2-3; Attorney General Reply Brief at 3, citing The Berkshire Gas Company, D.P.U. 92-210, at 202-203 (1993)).

In response to the Companies' assertion that the revised rate design proposal does not improperly shift costs to NSTAR Electric customers by combining NSTAR Electric and WMECo into a single revenue requirement, the Attorney General asserts that the Department has not authorized, and the Companies did not initially file their rate case using a combined revenue requirement (Attorney General Reply Brief at 3). Moreover, the Attorney General claims that the Companies stated in their revised proposal that the proposed merger would not affect rates in this case; however, the Attorney General maintains that the merger results in significant, adverse impacts to hundreds of thousands of customers in eastern Massachusetts (Attorney General Brief at 4; Attorney General Reply Brief at 4, citing Attorney General Brief at 3).

Moreover, the Attorney General notes the difficulty in reviewing the compliance filing if the Department approves the Companies' revised rate design proposal (Attorney General Brief at 15-16). The Attorney General recommends that the Department reject the revised rate design proposal because it is not gradual, fair, or cost-based (Attorney General Brief at 16). Further, the Attorney General maintains that the revised rate design proposal does not meet the Department's efficiency principle – that rates should reflect the cost of providing service (Attorney General Reply Brief at 3).

ii. Bill Impacts

The Attorney General claims that the Companies' arguments regarding bill impacts are not based on record evidence and obscure actual bill impacts (Attorney General Reply Brief at 4, citing Companies Brief at 37-38). According to the Attorney General, the Companies provided bill impacts based on their initial rate design proposal and not their revised proposal (Attorney General Reply Brief at 4, n.2). Moreover, the Attorney General contends that the alleged bill impacts in the Companies' brief represent the impact for an average customer or the customer class as a whole (Attorney General Reply Brief at 4). The Attorney General maintains that the bill impact to an average customer is meaningless when measuring the impact of increasing a customer charge (Attorney General Reply Brief at 4). The Attorney General asserts that, rather than using an average customer's bill, it is more important to consider a lower-use customer's bill when evaluating the impact of increasing a customer charge (Attorney General Reply Brief at 5).

iii. Attorney General's Recommendation

According to the Attorney General, the Department should direct Eversource to move its rates closer to cost of service before achieving distribution rate consolidation (Attorney General Brief at 17). The Attorney General recommends that the Companies propose consolidation after their distribution rates have grown closer together among the service territories (Attorney General Brief at 17, citing Exh. AG-SJR-1, at 21). According to the Attorney General, it would be unreasonable for the Department to allow residential customers' bills to change by more than 1.5 times and/or less than 0.5 times the class average increase given the Companies' mitigation proposals for other rate classes (Attorney General Brief at 12, 17, citing Exh. AG-SJR-1, at 23, 28-29, 34). The Attorney General maintains that her proposal moves distribution rates toward rate consolidation, while each class moves closer to cost of service, and is sensitive to other rate design goals (Attorney General Brief at 17). Therefore, the Attorney General recommends that the Department adopt her rate design proposal because it is based on cost of service and meets all rate design principles (Attorney General Brief at 18; Attorney General Reply Brief at 4).

b. Acadia Center

Acadia Center acknowledges that a certain degree of consolidation and alignment of rates is warranted, but contends that identical pricing and rate classes spanning the Companies' services territories contravene rate design principles and efficiency goal (Acadia Center Brief at 7). Acadia Center maintains that the issue of corporate structure should not take precedence over application of rate design principles when designing distribution rates (Acadia Center Brief at 7).

According to Acadia Center, the Companies currently maintain separate financial records for NSTAR Electric and WMECo, but intend to consolidate these into one set after the Department approves their merger (Acadia Center Brief at 9, citing Tr. 16, at 3218-3219, 3301- 3302). Acadia Center argues that the Companies should continue to maintain separate financial records for costs that are separate (e.g., substation investments) to use in preparing separate cost of service studies (Acadia Center Brief at 9, citing Tr. 16, at 3302).

Further, Acadia Center argues that the Companies' revised rate design proposal contravenes the Department's rate design principles (Acadia Center Brief at 8). Acadia Center maintains that the Companies' revised rate design proposal causes deliberate cross-subsidies because it ignores cost distinctions between WMECo and NSTAR Electric (Acadia Center Brief at 8). According to Acadia Center, distribution rates should reflect cost distinctions that can be and have been tracked separately for groups of customers (Acadia Center Brief at 8). Specifically, Acadia Center asserts that assigning WMECo's costs to NSTAR Electric, particularly NSTAR Electric's residential customers, to mitigate rate increases is inconsistent with the Department's rate design principles of efficiency and fairness (Acadia Center Brief at 8).

c. Cape Light Compact

i. Cost Allocation

Cape Light Compact argues that the Department should reject the Companies' revised rate design proposal and instead require the Companies to allocate base distribution revenue to NSTAR Electric and WMECo as proposed in the initial filing (Cape Light Compact Brief at 12). Cape Light Compact asserts that the Companies' revised rate design proposal unjustifiably and inequitably shifts a total of $17.2 million in base distribution costs to NSTAR Electric residential customers (Cape Light Compact Brief at 13). Of this amount, Cape Light Compact claims that the revised proposal shifts $12.8 million in base distribution costs from WMECo residential and non-residential customers to NSTAR Electric residential customers (Cape Light Compact Brief at 16, citing Exh. CLC-JFW-Supplemental-1, at 6 (Table 1)). Cape Light Compact asserts that the revised proposal shifts an additional $4.5 million in base distribution costs from NSTAR Electric non-residential customers to NSTAR Electric residential customers (Cape Light Compact Brief at 16, citing Exh. CLC-JFW-Supplemental-1, at 8).[22]

Cape Light Compact argues that the revised rate design proposal results in NSTAR Electric residential customers paying for costs incurred to serve WMECo residential and non-residential customers (Cape Light Compact Brief at 16, citing Tr. 16, at 3300). Given that NSTAR Electric and WMECo have been separate corporate entities with distinct revenue deficiencies driven by distinct capital investment needs, Cape Light Compact argues that the revised rate design proposal, which allocates costs to customers on whose behalf NSTAR Electric or WMECo did not invest, contravenes the Department rate design principle of efficiency causation (Cape Light Compact Brief at 17; Cape Light Compact Reply Brief at 4-7). Additionally, Cape Light Compact claims that, as the Companies acknowledge, the revised proposal results in an unintended cost shift, causing NSTAR Electric residential customers to subsidize WMECo residential and non-residential customers as well as NSTAR Electric non-residential customers (Cape Light Compact Brief at 18, citing Tr. 16, at 3327, 3329; Cape Light Compact Reply Brief at 6). As such, Cape Light Compact argues that the

22 Numbers in this paragraph do not add due to rounding.

revised rate design proposal contravenes the Department's rate design principle of fairness (Cape Light Compact Brief at 13, 17). Finally, Cape Light Compact claims that the Companies' proposal to consolidate base distribution cost allocation is a significant change to their rate structure and results in significant impacts to Eversource customers (Cape Light Compact Brief at 20). Accordingly, Cape Light Compact argues that the revised rate design proposal contravenes the Department rate design principles of continuity and gradualism and should be rejected (Cape Light Compact Brief at 19-21).

Cape Light Compact reiterates that the consolidated ACOSS includes invalid and improper assumptions and results in rates that contravene the Department's rate design principle of efficiency (Cape Light Compact Reply Brief at 4-5). Cape Light Compact adds that the Companies' attempt to justify the consolidation of NSTAR Electric and WMECo by noting the corporate consolidation is not germane because the unified cost tracking applies to costs incurred going forward, not to the recovery of historical costs (Cape Light Compact Reply Brief at 5-7). Additionally, Cape Light Compact argues that the Companies' proffering of the consolidation of legacy NSTAR Electric territories Boston Edison, Cambridge Electric Light, and Commonwealth Electric as evidence for ignoring historical cost incurrence is also irrelevant, as it does not show that the cost structures did not justify differing rates when those rates were approved (Cape Light Compact Reply Brief at 7). Instead, Cape Light Compact argues that Eversource's comparison of differing charges across the legacy NSTAR Electric territories only shows that the rates were set based on separate revenue requirements when they were approved (Cape Light Compact Reply Brief at 7).

In conclusion, Cape Light Compact recommends that the Department reject the revised rate design proposal and allocate base distribution revenues as proposed in the Companies' initial filing, with separate revenue requirements for NSTAR Electric and WMECo (Cape Light Compact Brief at 28). Cape Light Compact adds that, should the Department order modifications to the cost allocation proposed in the Companies' initial filing in any way, it should reject any variation that allows Eversource to shift costs from WMECo solely onto NSTAR Electric residential customers (Cape Light Compact Brief at 28).

ii. Bill Impacts

Cape Light Compact asserts that Eversource's revised rate design proposal results in high total bill impacts to Commonwealth Electric customers (Cape Light Compact Brief at 67-68). Cape Light Compact claims that reassigning customers to new rate classes based on changes to the determination of demand and eliminating seasonal rates contributes to the high total bill impacts (Cape Light Compact Brief at 71).

Specifically, Cape Light Compact claims that Eversource has not sufficiently justified its choice of a three-month average demand to classify customers (Cape Light Compact Brief at 73-74). Cape Light Compact adds that this change significantly impacts small businesses with seasonal peak demand but overall low annual usage and would result in individual bill increases up to $25,000 per year (Cape Light Compact Brief at 74, citing Exh. CLC-KFG-1, at 14). Cape Light Compact maintains that the high bill impacts resulting from the change in rate class definitions are inconsistent with the Department's rate design goals of continuity and fairness (Cape Light Compact Brief at 74). Cape Light Compact recommends that the Department apply a twelve-month average demand to classify customers unless and until Eversource can prove another determination fairly reflects customers' overall usage and contribution to coincident peak demand (Cape Light Compact Brief at 79). Cape Light Compact adds that Eversource's defense of the three-month average uses a hypothetical example that belies the data on the record and, overall, does not satisfy its burden to demonstrate that the rate classifications result in just, reasonable, and nondiscriminatory rates (Cape Light Compact Reply Brief at 15-16).

Additionally, Cape Light Compact argues that the elimination of seasonal rates also contributes to the high total bill impacts (Cape Light Compact Brief at 71). Cape Light Compact explains that this proposal adversely affects Cape Cod and Martha's Vineyard customers and moves away from rates that are cost-based, promote efficient usage, and offer more pricing options to customers (Cape Light Compact Brief at 75, citing Exh. AC-ML-1, at 4). Cape Light Compact contends that Eversource's attempt to treat the Commonwealth Electric Company service territory as it treats other areas of Massachusetts with year-round economies is a step in the wrong direction (Cape Light Compact Brief at 75, citing Exh. AC-1-15). Cape Light Compact explains that the Commonwealth Electric Company service territory has a seasonal tourist economy and part-time residents who will be harmed by eliminating seasonal rates (Cape Light Compact Brief at 75, citing Exh. CLC-KFG-1, at 12, lines 9-12). Further, Cape Light Compact claims that Eversource's argument that the bill impacts are not significant ignores customers hurt by the elimination of seasonal rates

(Cape Light Compact Reply Brief at 16). Cape Light Compact concludes that the Department should ensure that the rates it approves in this proceeding do not result in sudden, adverse bill impacts for seasonal customers (Cape Light Compact Brief at 76).

Finally, Cape Light Compact argues that the revised rate design proposal is inconsistent with the statutory restrictions set out by Section 94I (Cape Light Compact Brief at 68). Cape Light Compact claims that Section 94I limits base distribution rate increases to no more than ten percent for each rate class (Cape Light Compact Brief at 69). Cape Light Compact argues that Eversource's interpretation of Section 94I instead applies a ten-percent cap to the total revenue increase for each rate class, including consolidated base distribution revenue, pro forma reconciling revenue, and basic service revenue (Cape Light Compact Brief at 69, citing Exh. ES-RDP-1, at 39). Cape Light Compact argues that capping rates using percentages of total revenue, as Eversource proposes, allows the degree of cross-subsidization and distribution rate increases permitted to vary substantially in different proceedings and among different companies depending on the amount of forecasted reconciling and basic service revenue (Cape Light Compact Brief at 69). Thus, Cape Light Compact maintains that, although the Department has previously approved the method Eversource proposes, allowing the distribution rate cap to rise and fall with the size of reconciling revenue and basic service revenue is inconsistent with Section 94I and undermines the Legislature's inclusion of an explicit numerical cap (Cape Light Compact Brief at 69-70). Cape Light Compact requests that the Department cap distribution revenue increases at ten percent and apply the ten-percent cap to each group of customers moving from one class to another to avoid arbitrary rate class definitions (Cape Light Compact Brief at 70). Cape Light Compact adds that, although Eversource argues that adopting Cape Light Compact's interpretation of the cap would result in frequent rate cases, the Legislature, in fact, required more frequent rate filings when it amended Section 94 in 2012 (Cape Light Compact Reply Brief at 17).

iii. C&I Rate Mitigation

Cape Light Compact argues that Eversource did not file its mitigation plan in a timely manner, did not provide an effective plan to educate customers about their bill impacts, and did not propose sufficient rate relief to avoid excessive bill impacts (Cape Light Compact Brief at 76, citing Exhs. CLC-KFG-1, at 4; CLC-KFG-Supplemental-1, at 12). Cape Light Compact contends that Eversource's initial details regarding outreach and education plans for Commonwealth Electric customers moving between rate classes were insufficient because they did not provide important information such as how impacted customers would be identified, how and when they would be contacted, and what options Eversource would provide the customers (Cape Light Compact Brief at 76-77). Cape Light Compact asserts that the Companies' subsequent mitigation plan, filed July 25, 2017, was also deficient because a number of Commonwealth Electric Company customers would still experience serious bill impacts (Cape Light Compact Brief at 77, citing Exh. CLC-KFG-Supplemental-1, at 12). Cape Light Compact adds that the July 25, 2017 filing still does not have a detailed education plan (Cape Light Compact Brief at 78, citing Exh. CLC-KFG-1, at 2).

Cape Light Compact, thus, recommends that the Department direct Eversource to do the following: (1) submit a detailed education plan by January 1, 2019 that allows sufficient time for customers to be meaningfully educated about the rate changes in time to budget for them and/or install energy efficiency solutions; (2) mitigate adverse bill impacts for seasonal customers; (3) provide stronger mitigation discounts and/or more gradual increases for customers who would, under the Companies' mitigation plan, still face cumulative distribution rate increases of 25 percent or more over the next five years; (4) conduct targeted outreach by January 1, 2019 to individual customers who would face a cumulative distribution rate increase of 15 percent or more in the first two years after the proceeding; (5) provide an online bill calculator by January 1, 2019; and (6) work cooperatively with Cape Light Compact on mitigation measures, including sharing bill impact data to identify impacted customers (Cape Light Compact Brief at 79).

d. Cambridge

i. Consolidation and Alignment

Cambridge maintains that the Companies' initial and revised rate design proposals cause Cambridge Electric Light Company customers to experience "excessive" rate increases in 2018, followed by rate reductions in 2019 (Cambridge Brief at 12, 13, citing Exh. FEA-AMA-1, at 7). Cambridge alleges that the "up-and-down" approach is disruptive to customers because it sends erratic price signals and over-charges customers in 2018 (Cambridge Brief at 13, citing Exh. FEA-AMA-1, at 8). Therefore, Cambridge recommends that the Department limit the 2018 rate increase to the otherwise applicable 2019 rate increase (Cambridge Brief at 13).

Moreover, Cambridge maintains that the revised rate design proposal does not meet the Department's rate design goals of efficiency and fairness (Cambridge Brief at 4). According to Cambridge, billing customers to recover costs that Eversource incurred to serve other customers does not produce fair or efficient rates (Cambridge Brief at 4-5, citing Exhs. CLC-JFW-Supplemental-1, at 7-8; AC-ML-8, at 1-2). Cambridge alleges that the Companies' revised rate design proposal shifts $17 million in costs to NSTAR Electric's residential customers from WMECo's customers (Cambridge Brief at 3, citing Exh. CLC-JFW-Supplemental-1, at 6-7). Cambridge maintains that the driver of this cost shift is Eversource's proposal to consolidate the revenue requirement and rate design for NSTAR Electric and WMECo customers (Cambridge Brief at 3, citing Exhs. ES-RDP-Rebuttal-1, at 15 (May 19, 2017); CLC-JFW-Supplemental-1, at 4-5).

Cambridge maintains that it is not appropriate to mitigate the rate increases to WMECo by increasing rates for NSTAR Electric customers (Cambridge Brief at 5). Therefore, Cambridge asserts that the Department should reject the Companies' revised rate design proposal, except for the optional two-part rate that would be available to Cambridge Electric Light Company customers on legacy Rate G-0 and Rate G-5 (Cambridge Brief at 5 and 15, citing Exh. DPU-63-6 (Supp.) at 6-7). Cambridge recommends that the Department approve the two-part rate so that these customers can avoid bill impacts exceeding 50 percent (Cambridge Brief at 15, citing Exh. ES-RDP-2, Sch. RDP-4 (East) at 15, 25).

i. Revenue Increase Cap Allocation (Basic Service)

Cambridge maintains that the Companies' bill impact analysis used basic service prices from the first quarter of 2017 (Cambridge Brief at 14; Cambridge Reply Brief at 3). According to Cambridge, basic service prices are the highest in the first quarter, and therefore, not representative of annual basic service prices (Cambridge Brief at 14; Cambridge Reply Brief at 3). Further, Cambridge alleges that the first quarter basic service prices in 2017 were three-cents per kilowatt hour ("kWh") higher than the annual per-kWh price in 2016 and higher than the annual average basic service price for the last seven of eight years (Cambridge Brief at 14, citing Exh. ES-RDP-Rebuttal-1, at 17).

Cambridge argues that the selection of basic service prices used in the calculation of the total bill informs the magnitude of the percentage bill impact (Cambridge Brief at 14). Therefore, Cambridge alleges that a higher basic service price inflates the denominator in the bill impact calculation and leads to a lower percentage bill impact overall (Cambridge Brief at 14; Cambridge Reply Brief at 3). Cambridge provides as an example that the bill impact for the proposed consolidated Rate G-3 is 14.4 percent using the first quarter basic service price, but the bill impact increases to 17.2 percent using the 2016 annual average basic service price (Cambridge Brief at 14-15, citing Exh. NECEC-9-3, Att. at 28). Cambridge contends that the 17.2-percent bill impact is above the Companies' proposed mitigation threshold of 15 percent (Cambridge Brief at 14-15).

In response to Eversource's argument that first quarter 2017 prices are appropriate because they are the most current, Cambridge alleges that it is also important to use a price that is representative of the projected time period (Cambridge Reply Brief at 3). According to Cambridge, the Companies calculate annual rate increases, not quarterly rate increases (Cambridge Brief at 3). Moreover, Cambridge argues that a quarterly price distorts the results because basic service prices vary in each quarter (Cambridge Reply Brief at 3). Therefore, Cambridge recommends that the Department direct Eversource to use the 2016 annual average basic service price in its bill impact calculations as to include all eligible customers to receive mitigation (Cambridge Brief at 15, citing Exh. TEC-JB-2, at 6; Cambridge Reply Brief at 3).

e. DOER

DOER argues that the Companies' initial rate design proposal drew concern from members of the Legislature, municipalities, and the business community due to the high bill impacts to customers in western Massachusetts (DOER Brief at 2, citing Letter from Berkshire Delegation to Chairwoman O'Connor (May 31, 2017)). According to DOER, the bill increases in western Massachusetts will have negative impacts on the region's economy (DOER Brief at 2, citing Letter from Berkshire Delegation to Chairwoman O'Connor (May 31, 2017)). Therefore, DOER recommends that the Department reject the Companies' initial rate design proposal (DOER Brief at 2).

While DOER recognizes that the Companies' revised rate design proposal reduces the number of customers that experience high bill impacts, DOER maintains that some C&I customers may still experience significant bill increases under the revised rate design proposal (DOER Brief at 2-3, citing Exh. DOER-4-2, Atts. (a)-(d), (f), (h), (j)). DOER also maintains that the Companies' proposal is not clear whether some C&I customers will receive greater than 15-percent bill increases in multiple years (DOER Brief at 3). Therefore, DOER recommends that the Department scrutinize the Companies' revised rate design proposal to ensure that no individual customer will experience unreasonable bill impacts (DOER Brief at 3-4). DOER also recommends that the Department require more stringent mitigation strategies so that customers do not receive excessive bill impacts (DOER Brief at 4). While DOER defers to the Department's judgment, DOER suggests that the Department could direct the Companies to implement their rate design proposal more gradually, to evaluate whether each customer was assigned to the appropriate aligned rate class, and to collaborate with customers to deploy successful energy efficiency measures (DOER Brief at 4).

f. FEA

i. Revised Proposal

FEA argues that both the initial and revised rate design proposals result in unjustified rate impacts for the proposed Boston Edison Company consolidated Rate G-4 customers (FEA Brief at 5; FEA Reply Brief at 1). Further, FEA contends that the Companies' proposal for moving legacy Boston Edison Company Rate G-3 customers to aligned Rate G-4 contravenes the Department's rate design goals of efficiency, rate continuity, fairness, and earnings stability because it imposes a temporary increase in 2018 (FEA Reply Brief at 2). For example, FEA contends that legacy Rate G-3 Boston Edison Company customers would experience a rate increase in 2018 followed by a rate decrease in 2019, which FEA alleges is not cost-based (FEA Brief at 5, 6; FEA Reply Brief at 1). FEA argues that the consolidated rates in 2019 are based on an ACOSS for the consolidated NSTAR Electric rate classes (FEA Brief at 6). Further, FEA asserts that the Companies have not shown that their cost to serve legacy Boston Edison Company customers will increase in 2018 and subsequently decrease in 2019 (FEA Brief at 6; FEA Reply Brief at 1).

FEA also argues that the Companies' ACOSS does not account for the differences in current revenues among NSTAR Electric's three legacy service territories because the Companies consolidate the three territories into one NSTAR Electric territory (FEA Brief at 8). Thus, FEA contends that the Companies' ACOSS does not provide a meaningful evaluation of Boston Edison Company's legacy Rate G-3 rate class's current revenue compared to the cost of service (FEA Brief at 8).

FEA argues that Eversource should provide customers with the same earnings stability that it requests by developing stable energy charges for its customers (FEA Reply Brief at 2). Therefore, FEA recommends that any increase in rates should be smoothed over the initial two years, and that these legacy Rate G-3 customers do not receive a rate increase in 2018 (FEA Brief at 6, 9; FEA Reply Brief at 2). FEA also recommends that the Department should allow legacy Boston Edison Company Rate G-3 distribution rates to remain unchanged in 2018 and should approve the distribution rate decrease for 2019 according to the Companies' proposal (FEA Reply Brief at 3).

Additionally, FEA alleges that the Companies acknowledge that legacy Boston Edison Company customers subsidize Cambridge Electric Light Company customers and

Commonwealth Electric Company customers (FEA Reply Brief at 2-3, citing Companies Brief at 50-51). FEA contends that these customers receive the same electric service from a fully-consolidated NSTAR Electric (FEA Reply Brief at 3). Thus, FEA argues that the Companies' proposal to increase 2018 rates followed by a decrease in 2019 further exacerbates the subsidy that Boston Edison Company customers provide to Cambridge Electric Light Company and Commonwealth Electric Company customers (FEA Reply Brief at 3, citing Exh. DPU-18-21, Att. (A2)).

Moreover, FEA argues that the 2018 increase for legacy Boston Edison Company customers funds the consolidation of rates (FEA Brief at 7). For example, FEA contends that legacy Commonwealth Electric Company customers taking service on Rate G-3 receive a rate decrease in 2018 that is less than the 2019 consolidated rate (FEA Brief at 6-7). Therefore, FEA contends that legacy Commonwealth Electric Company Rate G-3 customers receive favorable treatment that results in "unjustified economic harm" to legacy Boston Edison Company customers (FEA Brief at 7). As a result, FEA alleges that the Companies' proposal to consolidate rates conflicts with the Department's finding that merger-related costs cannot be collected from customers unless they are offset by merger-related savings (FEA Brief at 7, citing NSTAR/Northeast Utilities Merger, D.P.U. 10-170-B (2012)). Therefore, FEA recommends that any reduction to the proposed revenue requirement be used to offset negative bill impacts under the Companies' consolidation and alignment proposal (FEA Brief at 9).

ii. Attorney General's Proposal

FEA supports the Attorney General's recommendation to impose the 2018 revenue increases based on four separate ACOSS because it allows for all legacy-priced customers to be evaluated accurately according to cost of service (FEA Brief at 8). However, FEA contends that because the Attorney General does not support the Companies' 2019 rate consolidation proposal, legacy Boston Edison Company customers that FEA claims are already priced above other similarly-situated NSTAR Electric customers, would not receive an appropriate rate decrease in 2019 (FEA Brief at 8). Therefore, FEA does not support the Attorney General's proposal that no customer within a rate class receives no greater than 1.5 times or no less than 0.5 times the class average increase (FEA Brief at 8). FEA claims that the Attorney General's proposal is not consistent with the Department's rate design precedent (FEA Brief at 8, citing Exh. ES-RDP-1, at 42). Instead, FEA contends that the 200-percent cap on the Companies' average increase is consistent with Department precedent (FEA Brief at 8). If the Department adopts the Attorney General's recommended rate design, FEA argues that the Department should implement the 200-percent cap and provide customers that would have had a rate decrease under the Companies' consolidation plan with no rate increase instead (i.e., Boston Edison Company customers in Rate G-1/T-1, Rate G-2/T-2, and Rate G-3) (FEA Brief at 9, citing Exh. FEA-AMA-Surrebuttal-2).

g. NECEC

NECEC argues that the Companies' rate design consolidation proposals are not consistent with the Department's rate structure goals (NECEC Brief at 8, citing

Exh. AG-SR-1, at 3-4; NECEC Reply Brief at 3). NECEC contends that the Companies' argument that their proposal is consistent with the Department's rate structure goals because it is based on an ACOSS is not true because there are two steps in determining rate structure: cost allocation and rate design (NECEC Brief at 3, citing Companies Brief at 36; D.P.U. 15-155, at 384).

NECEC asserts that the Companies' proposed rate consolidation undermines rate continuity and gradualism, causes distressing bill impacts, and eliminates efficient rate designs (NECEC Brief at 3, 19). NECEC also asserts that the Companies' proposal to consolidate rates contravenes the Department's goal of rate continuity because it is not gradual and does not allow customers to adjust their consumption patterns (NECEC Brief at 14, citing Exh. AG-SJR-1, at 3-4; NECEC Brief at 15; NECEC Reply Brief at 3, citing Exh. AG-SJR-1, at 20-22, 36; NECEC Reply Brief at 4, citing D.P.U. 15-155, at 384). Further, NECEC argues that the Companies' rate consolidation proposal contravenes the rate structure goal of continuity because it causes an abrupt change of rate structures on rates that have been in place for decades (NECEC Brief at 14, citing Exh. AG-SJR-1, at 3-4). In addition, NECEC asserts that a year delay does not constitute gradualism especially when, as NECEC alleges, Eversource admits that it has maintained the existing rate structures for decades (NECEC Brief at 15; NECEC Reply Brief at 2, citing Exhs. ES-RDP-1, at 5; ES-RDP-Rebuttal-1, at 8 (May 19, 2017)). Therefore, NECEC alleges that it is not necessary for the Companies to consolidate and align their rates within two years, which creates excessive bill impacts for many customers (NECEC Reply Brief at 2-3, citing Exh. AG-SJR-1, at 20-22, 36).

According to NECEC, the Companies' initial and revised rate design consolidation proposals result in "extraordinary and unreasonable" bill impacts and are arbitrary (NECEC Brief at 15, citing Exhs. AG-SJR-1, at 3-4, 24-36; CLC-PLC-1, at 13-15; NECEC Reply Brief at 2; NECEC Reply Brief at 4, citing Exh. AG-SJR-1, at 4, 23-25, 35-36, 39-40). NECEC asserts that some C&I customers would experience bill impacts by very large percentages, and in some cases, more than 100 percent (NECEC Brief at 16, citing Exh. AG-SJR1, at 36). NECEC contends that the proposed rate design creates "winners and losers" based on legacy rate design (NECEC Brief at 15, citing Exh. AG-SJR-1, at 23-24). For example, NECEC alleges that some customers will experience bill increases of more than 25 percent while the customers' rate class receives a revenue reduction and conversely, some customers will experience bill decreases while the associated rate class revenue requirement increases (NECEC Brief at 16, citing Exh. AG-SJR-1, at 39-40). NECEC adds that residential customers will experience very different impacts caused by the increase to their customer charge and/or their consumption charges (NECEC Brief at 16, citing Exhs. AG-SJR-1, at 24-25, 31-33; CLC-PLC-1, at 6, 16; CLC-JFW-1, at 5-6). According to NECEC, these bill impacts are unreasonable and arbitrary (NECEC Brief at 16, citing Exh. AG-SJR-1, at 26-27). NECEC argues that Eversource should consolidate and align its rates more gradually so as to be more sensitive to customer bill impacts (NECEC Brief at 8, 17, citing Exh. AG-SJR-1, at 20). According to NECEC, Eversource did not provide justification for its rate consolidation other than simplifying its rate offerings (NECEC Brief at 16-17, citing Exh. AG-SJR-1, at 36).

NECEC alleges that the Companies' proposed rate design does not improve efficiency and weakens price signals sent to customers (NECEC Reply Brief at 3, citing D.P.U. 15-155, at 383-384, 483). NECEC maintains that the Companies' rate design proposals will prevent customers from making future investments related to their energy costs, such as energy efficiency and on-site generation, and will shake the confidence of markets that allow private capital to flow into such projects (NECEC Brief at 19, citing Exhs. UMASS-RS-1, at 57-58; SREF-TW/MW-1, at 30-31; 1-MS-1, at 4-5; SREF-TW/MW-1 (Supp.) at 28; NEWT-1, at 7-10; TOB-DW-1, at 3; NECEC Reply Brief at 5, citing Exhs. TOB-DW-1, at 3, 8-12; SVEC-JR-1, at 3; 1-JWM-1, at 9-10; CVEC-CAW-2, at 4). Moreover, NECEC argues that the Department must consider impacts on the development of energy efficiency and on-site generation from any actions it takes regarding rate design (NECEC Reply Brief at 5, citing G.L. c. 164, §§ 141, 142).

Therefore, NECEC recommends that the Department reject Eversource's rate design consolidation and alignment proposal and retain all existing non-residential rate classes (NECEC Brief at 8; NECEC Reply Brief at 2). NECEC asserts that the Department's acceptance of the Companies' rate design proposal will impose excessive bill impacts on customers and may undermine the Commonwealth's energy policies (NECEC Reply Brief at 5).

h. TEC

i. Annual Base Rate Changes

While TEC supports rate consolidation in principle, TEC alleges that there are several problems with Eversource's rate design proposal (TEC Brief at 20, 21). Specifically, TEC maintains that some groups of customers, such as Boston Edison Company's legacy Rate G-3, will experience a rate increase in 2018 followed by a rate decrease in 2019 (TEC Brief at 5, 21). TEC argues that the 2018 increase is a merger integration cost that should be borne by the Companies (TEC Brief at 21, citing Exh. FEA-AMA-2, at 8-10). Further, TEC alleges that any rate increase for Boston Edison customers in 2018 is neither cost-based nor supported by the Companies' ACOSS (TEC Brief at 21; TEC Reply Brief at 9). According to TEC, rate consolidation and alignment should avoid cross subsidies within existing rate classes and erratic movements in rates (TEC Brief at 21; TEC Reply Brief at 9). Therefore, TEC argues that the Department should reject a rate design proposal that results in a rate increase in 2018 followed by a rate decrease in 2019 because that contravenes the Department's rate design goal of gradualism and sends erratic price signals to customers (TEC Brief at 5, 21).

ii. Revenue Increase Cap Allocation (Basic Service)

TEC maintains that the allocation of the final revenue requirement that the Department approves is subject to two caps: (1) a statutory ten-percent cap on the overall increase; and (2) the Department's cap that limits the increase to no more than double the average increase across all rate classes (i.e., a 200-percent cap on the distribution revenue increase)

(TEC Brief at 8). TEC asserts that the Department should direct Eversource to use a representative value for basic service for the purposes of determining either cap (TEC Brief at 8). TEC maintains that Eversource should use the twelve-month average of basic service prices in the cap allocation formula so that the Department's decision is based on accurate and realistic data to evaluate the allocation of the revenue requirement increase (TEC Brief at 8). TEC contends that using a representative twelve-month average of basic service prices will also more fairly determine the eligibility screening for bill mitigation for C&I customers (TEC Brief at 8). TEC argues that the Companies' data are unrepresentative and should not be used (TEC Brief at 8, citing Exh. TEC-JB-2, at 4-7).

According to TEC, the Companies used basic service prices of \$0.10165 per-kWh, \$0.11022 per-kWh, and \$0.10144 per-kWh for C&I customers in the West/Central Massachusetts, Northeast Massachusetts and Boston, and Southeast Massachusetts zones, respectively (TEC Brief at 9, citing Exh. TEC-JB-2, at 2). TEC argues that these basic service prices are not representative because they are at the high end of average annual prices experienced over the last several years (TEC Brief at 9, citing Exhs. TEC-JB-2, at 2-5; ES-RDP-Rebuttal-1, at 17). Accordingly, TEC maintains that the higher than average basic service prices skew the application of the ten-percent and 200-percent caps (TEC Brief at 9). TEC asserts that using higher basic service prices is unfair to many customers because it: (1) understates the magnitude of rate increase; (2) violates the purpose of cap allocation formula; and (3) improperly apportions a greater percentage of revenue requirement to C&I customers (TEC Brief at 9).

In response to the Companies' argument that basic service prices are trending upwards and it is more appropriate to use the most current prices, TEC maintains that Eversource should have used June 2017 basic service rates in its revised rate design proposal (TEC Reply Brief at 8). Instead, TEC asserts that the Companies are "cherry picking" the most favorable basic service prices for their bill impact calculations (TEC Reply Brief at 8).[23]

For these reasons, TEC recommends that the Department reject the unrepresentative basic service prices that the Companies used in the cap allocation calculations (TEC Brief at 9; TEC Reply Brief at 7). TEC also recommends that the Department direct the Companies to use the twelve-month average basic service prices for the large C&I rate classes (TEC Brief at 4, 9; TEC Reply Brief at 7, 9).

i. UMass

UMass asserts that all of Eversource's rate design proposals share a common theme of placing the interests of its shareholders above the interests of its customers (UMass Brief at 10; UMass Reply Brief at 10). UMass argues that Eversource appears to have elevated the importance of earnings stability over the importance of balancing all of the Department's rate design goals (UMass Brief at 2).

UMass recommends that the Department initiate a separate process to consider new rate designs that would be compatible with the Commonwealth's public policies regarding the future of energy (UMass Brief at 1-2, 3, 12; UMass Reply Brief at 10). UMass contends

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23 Moreover, TEC alleges that basic service prices have been volatile, and winter basic service prices have been much higher than prices at other times of the year (TEC Reply Brief at 8).

that the adversarial process of a rate case is not the proper forum to investigate and evaluate material changes to rate design (UMass Brief at 12-13).

UMass asserts that the Department should consider, in this separate process, more fundamental adjustments to rate design that balance utility and customer interests, as well as interests among and between customers (UMass Reply Brief at 10). UMass maintains that the rate design that the Department adopts in this proceeding should be provisional and subject to any changes that are a product of any future process that the Department may initiate (UMass Brief at 14).

j. Vote Solar

Vote Solar maintains that in all decisions on rate design, the Department must "consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation" (Vote Solar Brief at 18, citing G.L. c. 164, § 141). According to Vote Solar, the evidence that Eversource provided prevents compliance with this obligation (Vote Solar Brief at 2, 18, citing D.P.U. 15-155, at 458-459). Vote Solar argues that the Companies did not undertake analyses of effects of their rate design proposals, specifically small C&I demand charges, on incentives to reduce demand, achievement of the Companies' or Cape Light Compact's Three-Year Energy Efficiency Plan, or the deployment of distributed generation (Vote Solar Brief at 18, citing Exhs. VS-4-1; VS-4-2; VS-4-3; VS-4-4).

Vote Solar argues that customers are incentivized to reduce consumption through higher per-kWh charges (Vote Solar Brief at 19, citing Exh. VS-4-2). According to Vote

Solar, the Companies' proposed demand charges will lower the per-kWh distribution charges by as much as 60 percent for some customers (Vote Solar Brief at 19, citing Exh. VS-NP-RRD-1, at 6; Tr. 17, at 3514). Therefore, Vote Solar concludes that this scenario is a "serious cause for concern" for the Department (Vote Solar Brief at 19, citing D.P.U. 15-155, at 458-459).

k. WMIG

i. Initial and Revised Rate Design Proposals

WMIG asserts that the Companies' revised rate design proposal is more equitable than their initial rate design proposal and reflects fairness, stability, gradualism, and efficiency (WMIG Brief at 3, 4; WMIG Reply Brief at 3). According to WMIG, the revised rate design proposal results in less severe bill impacts to WMECo's C&I customers and is better overall for consumers than the Companies' initial rate design proposal (WMIG Brief at 5). Moreover, WMIG contends that the revised rate design proposal is consistent with the Companies' goals to unify Eversource's legacy companies in a fair and efficient manner (WMIG Brief at 5; WMIG Reply Brief at 4). WMIG maintains that the initial rate design proposal would have had a dramatic and negative impact on Berkshire County's economy (WMIG Brief at 6). WMIG contends that the revised rate design proposal protects C&I customers while not over burdening other customers (WMIG Brief at 6). WMIG notes, however, that the actual bill impacts will depend on the revenue requirement that the Department ultimately approves (WMIG Reply Brief at 4).

In response to the Attorney General's proposed rate design, WMIG agrees with the Companies that the Attorney General ignores the fact that customers' bills have multiple reconciling rates and that relying on simple percentages exaggerates bill impacts (WMIG Reply Brief at 4). Further, WMIG agrees with DOER's recommendation that the Department direct the Companies to apply additional mitigation to excessive bill increases gradually and predictably over time (WMIG Reply Brief at 4-5).

WMIG also maintains that the Companies' revised rate design proposal results in an increase in 2018 followed by a decrease in 2019 for some customers (WMIG Brief at 6; WMIG Reply Brief at 5). According to WMIG, this aspect of the proposal has negative impacts on both NSTAR Electric's and WMECo's customers (WMIG Brief at 6). WMIG asserts that a rate increase followed by a rate decrease sends customers an inconsistent rate signal (WMIG Brief at 6). WMIG argues that the Department should not allow the rate increase in 2018 because it contravenes the rate design goals of continuity and gradualism, and, in the alternative, WMIG suggests that a fair solution be found (WMIG Brief at 4, 6; WMIG Reply Brief at 5). Therefore, WMIG recommends that the Department adopt the Companies' revised rate design proposal with the modification recommended above (WMIG Reply Brief at 4-5, citing RR-DPU-50).

ii. Revenue Increase Cap Allocation (Basic Service)

WMIG argues that the Companies used a three-month basic service price at the most costly time of the year to calculate bill impacts (WMIG Reply Brief at 8). According to WMIG, the Companies' basic service price data are not representative of basic service prices

(WMIG Brief at 7). WMIG agrees with Cambridge and TEC that the Companies should use the twelve-month average of basic service prices for C&I customers for the statutory ten-percent cap allocation and the Department's 200-percent rule (WMIG Brief at 7, citing Exh. TEC-JB-2, at 5; WMIG Reply Brief at 7-8).

WMIG argues that basic service prices have a substantial effect on the percentage impact to a customer's bill, which affects the application of the statutory customer class bill impact cap (WMIG Reply Brief at 7). WMIG maintains that the Companies chose a higher basic service price that distorts their bill impact analyses (WMIG Reply Brief at 7). Further, WMIG asserts that C&I customers are allocated more than their fair share of the revenue requirement than appropriate under the application of the two caps (WMIG Brief at 7, citing Exh. TEC-JB-2, at 5). Therefore, WMIG maintains that using these basic service prices is unfair to many customers because this ingredient: (1) understates the magnitude of rate increase; (2) violates the purpose of cap allocation formula; and (3) improperly apportions a greater percentage of revenue requirement to commercial customers (WMIG Brief at 7). Moreover, WMIG agrees with Cambridge and TEC that the Companies' choice of basic service prices may ultimately exclude some C&I customers from receiving mitigation (WMIG Reply Brief at 7-8, citing Exh. TEC-JB-2, at 6).

According to WMIG, the "most recently effective rates" are the annual average basic service prices because these rates reflect the fluctuation of energy market prices making them more accurate (WMIG Reply Brief at 8, citing Fitchburg Gas and Electric Light Company, D.P.U. 13-90 at 247 (2014)). Therefore, WMIG recommends that the annual average for 2016 be used for the calculation (WMIG Reply Brief at 8).

l. Companies

i. Initial and Revised Proposals

According to the Companies, the goal of their initial rate design consolidation proposal was to balance the Department's policy goals and rate design objectives (Companies Brief at 36). Further, Eversource contends that it complied with Section 94I by setting rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent (Companies Brief at 36). The Companies allege they used total revenues to determine whether a customer class increase was greater than ten percent to account for impacts caused by changes in reconciling factors (Companies Brief at 36, citing Exh. ES-RDP-1, at 38). Eversource maintains that its proposed initial rate design results in reasonable bill impacts (Companies Brief at 37).

The Companies maintain that the Department should adopt their revised rate design proposal (Companies Brief at 28). Eversource maintains that its revised proposal is not arbitrary (Companies Brief at 48). According to the Companies, their revised proposal modified certain components of their initial proposal (Companies Brief at 48). Specifically, the Companies maintain that the overall structure of the rate design remained the same between the two proposals (Companies Brief at 49). Further, Eversource defends its use of a consolidated revenue requirement in its revised proposal by arguing that the Department approved the use of a consolidated revenue requirement in a National Grid rate case

(Companies Reply Brief at 9, citing Boston Gas Company, Essex Gas Company, and Colonial Gas Company each d/b/a National Grid, D.P.U. 10-55, at 2-3, 538, 544, 556-559 (2010)).

The Companies argue that their initial and revised proposed ACOSSs are fully supported and appropriately allocate the Companies' revenue requirement (Companies Reply Brief at 10). According to the Companies, their revised 2018 revenue targets by rate class are different from the 2018 revenue targets in the initial rate design proposal because the revised proposal is based on a legacy rate class ACOSS, while the initial proposal is based on consolidated and aligned rate classes (Companies Reply Brief at 10). Therefore, Eversource asserts that the Attorney General ignores the evidence with her argument that if the initial proposal was cost-based, then the revised proposal cannot be cost-based (Companies Reply Brief at 10).

The Companies maintain that FEA, TEC, and WMIG make an impractical recommendation that the Department should reject a component of the Companies' proposed revised rate design that causes distribution rates to increase temporarily in 2018 (Companies Brief at 29, 37-38). According to Eversource, the 2018 rate increase is a function of cost-based ratemaking to transition the legacy rate classes to the consolidated rate classes (Companies Brief at 29, 37, citing Exh. ES-RDP-Rebuttal-1, at 4 (August 22, 2017); DPU-56-9 (Supp.)). Moreover, Eversource argues that it would not recover its revenue requirement with 2018 rates unchanged (Companies Reply Brief at 37). The Companies assert that their approach in their revised rate design reduces mitigation in future years

(Companies Reply Brief at 29). Moreover, Eversource claims FEA's analysis of a Boston Edison Company Rate G-3 customer moving to proposed aligned Rate G-4 is misguided and not representative of the typical rate impact for customers in this rate class (Companies Reply Brief at 37). Therefore, the Companies maintain that the Department should reject FEA's argument that 2018 Boston Edison Rate G-3 rates should not be increased (Companies Reply Brief at 38).

In response to the Attorney General's argument that a large portion of the rate increase will impact a small group of customers, Eversource claims that the Attorney General uses selective analyses and ignores the total impact of all rate changes on a customer's bill (Companies Brief at 37; Companies Reply Brief at 3). Further, Eversource alleges that the Attorney General's rate design proposal is "overly simplistic" and ignores the reconciling rate component on a customer's bill (Companies Brief at 38; Companies Reply Brief at 3). For example, the Companies maintain that the Attorney General's calculation of a 115-percent increase for Commonwealth Electric residential customers is deceptive and unfair (Companies Brief at 38). Eversource asserts that the Attorney General does not acknowledge that an $8.00 customer charge represents only six percent of an average customer's bill (Companies Brief at 38). Eversource claims that the Attorney General's reliance on simple percentage increases for each rate component exaggerates bill impacts and is misleading (Companies Reply Brief at 3). The Companies maintain that the Department judges the reasonableness of proposed rates by evaluating bill impacts based on the percent of total bills, because customers do not individually judge the reasonableness of a change in a singular rate

(Companies Brief at 38, citing Exh. ES-RDP-Rebuttal-1, at 3 (May 19, 2017); Companies Reply Brief at 3). Further, Eversource asserts that rate changes that result in large percentage increases, but small dollar increases, should also be considered reasonable (Companies Brief at 38, citing Exh. ES-RDP-Rebuttal-1, at 3 (May 19, 2017)). Accordingly, the Companies maintain that the Attorney General's analyses do not demonstrate that the Companies' rate design proposal contravenes the rate design principles of continuity and gradualism (Companies Reply Brief at 3).

Moreover, the Companies argue that, although the Attorney General contends that the Companies' rate design proposals contravene the Department's rate design principles of continuity, fairness, and gradualism, the Attorney General does not describe any problems with continuity or gradualism caused by the Companies' revised rate design proposal (Companies Reply Brief at 2). According to Eversource, the Attorney General only claims that the revised rate design is not based on the cost of serving any customer class or service area (Companies Reply Brief at 2).

Further, the Companies maintain that they provided voluminous evidence supporting their revised rate design proposal with respect to continuity and gradualism (Companies Reply Brief at 4, citing Exhs. ES-RDP-2 (ALT1), Sch. RDP-9 (East); ES-RDP-2 (ALT1), Sch. RDP-9 (West); ES-RDP-3 (ALT1), Sch. RDP-3 (East); ES-RDP-3 (ALT1), Sch. RDP-3 (West); ES-RDP-4 (ALT1), Sch. RDP-3 (East); ES-RDP-4 (ALT1), Sch. RDP-3 (West); ES-RDP-4 (ALT1), Sch. RDP-4 (East); ES-RDP-4 (ALT1), Sch. RDP-4 (West); ES-RDP-4 (ALT1), Sch. RDP-5 (East); ES-RDP-4 (ALT1), Sch. RDP-5 (West); ES-RDP-4 (ALT1), Sch. RDP-6 (East); ES-RDP-4 (ALT1), Sch. RDP-6 (West); ES-RDP-4 (ALT1), Sch. RDP-7 (East); ES-RDP-4 (ALT1), Sch. RDP-7 (West); DPU-63-6 (Supp.), Atts. (f)-(m)). Eversource asserts that its five-year mitigation plan for C&I customers further supports its commitment to rate continuity and gradualism and will allow customers to adjust their load patterns (Companies Reply Brief at 4).

Moreover, the Companies argue that 98 percent of residential NSTAR Electric customers will not see a change in their rate structure, and WMECo residential customers will see very minimal changes in their rate structure (Companies Reply Brief at 5, citing Exh. ES-RDP-3 (ALT1), Sch. RDP-2 (East)). Eversource argues that, under its proposal, it will bill 86 percent of its C&I customers under "virtually the same" rate structure as their current rate structures (Companies Reply Brief at 5). According to the Companies, the 14 percent of C&I customers that will see a degree of change to their current rate structure are primarily those currently taking service on TOU rates (Companies Reply Brief at 5-6). Therefore, Eversource argues that its proposal maintains rate structures for the vast majority of customers while also addressing bill impacts through its mitigation proposal (Companies Reply Brief at 6).

Eversource contends that Cape Light Compact is not justified in its criticism that the Companies' revised rate design: (1) unfairly shifts costs to NSTAR Electric customers; (2) unfairly shifts costs from non-residential customers to residential customers; and (3) contravenes the Department's rate design principle of gradualism (Companies Brief at 49; Companies Reply Brief at 8). According to the Companies, their revised rate design proposal combines the NSTAR Electric and WMECo cost of service into one revenue requirement (Companies Reply Brief at 8, citing Exh. ES-RDP-Rebuttal-1, at 13 (August 22, 2017)). The Companies argue that Cape Light Compact's purported cost shifts only compare base distribution revenue targets and do not account for all the rate changes that a customer would face as a result of the Companies' proposal (Companies Brief at 51). According to Eversource, the elimination of lost base revenue and the sharing of transmission costs across Eversource results in a $17 million reduction to NSTAR Electric customers, while WMECo's costs will increase by $4.7 million from changes in reconciling rates under the revised rate design proposal (Companies Brief at 51, citing RR-DPU-50, Atts. (e) at 17-18 and (f) at 9-14).

The Companies argue that treating NSTAR Electric and WMECo as a combined operating company is not arbitrary because the Companies already are operating as a single company in Massachusetts under the supervision of a common management team and shared services (Companies Brief at 49; Companies Reply Brief at 8, citing Exh. ES-RDP-Rebuttal-1, at 13 (August 22, 2017)). Eversource claims that maintaining separate revenue requirements based on the availability of historical test year costs does not represent a more appropriate allocation of costs (Companies Brief at 50).[24] Further, Eversource claims that if the Department approves legal consolidation of NSTAR Electric

24 Eversource asserts that generally, under current rates, Boston Edison customers subsidize Commonwealth Electric and Cambridge Electric Light customers because the Companies maintained separate revenue requirements for the legacy NSTAR Electric Companies (Companies Brief at 51).

and WMECo, Eversource would financially consolidate its operations (Companies Brief at 49). Accordingly, the Companies maintain that budgeting would not be separate between the two legacy companies (Companies Brief at 49-50). Therefore, the Companies contend that it is appropriate for their customers to share costs incurred for providing service to them because the Companies currently incur costs that are shared across Massachusetts (Companies Brief at 49; Companies Reply Brief at 8-9, 11).

Eversource disagrees with the Attorney General's assertion that its 2018 revised rate design proposal is not cost-based and that there is no basis for a \$10 million shift to NSTAR Electric customers (Companies Reply Brief at 7, citing Attorney General Brief at 3). Eversource maintains that its 2018 rate design proposal is based on a legacy rate class ACOSS (Companies Reply Brief at 7, citing Exhs. ES-RDP-Rebuttal-1, at 2-3 (August 22, 2017); DPU-18-21, Atts.; DPU-56-7, Atts.). According to the Companies, the difference in revenue allocation at equalized rates of return between their initial and revised rate design proposals is an increase of \$3.5 million to NSTAR Electric (Companies Reply Brief at 8, citing RR-DPU-50, Att. (f) at 66). The Companies note, however, that the approved revenue targets by rate class are never set at equalized rates of return because doing so would produce results that violate G.L. c. 164, § 94I and the Department's rules for rate design (Companies Reply Brief at 8).

Moreover, the Companies disagree with the Attorney General that it will be difficult for the Department to review the Companies' revised rate design compliance filing (Companies Brief at 48, 51). Eversource maintains that compliance includes six steps and that the Department's review "can be accomplished in a straight forward and timely manner" (Companies Brief at 51-52, citing Exh. ES-RDP-Rebuttal-1, at 7-8 (August 22, 2017)).

ii. Section 94I

In response to Cape Light Compact's argument that the Department should apply the ten-percent cap in Section 94I to each group of customers moving from one class to another, Eversource claims that this rate structure treatment is contrary to Department precedent and statutory language (Companies Brief at 39-40, citing Cape Light Compact Brief at 70). According to the Companies, the Department applies the ten-percent cap to the overall bill impact for each rate class (Companies Brief at 40, citing D.P.U. 14-150, at 397-398). Further, Eversource argues that the statutory language does not indicate that the ten-percent cap be applied to individual customers, subsets, or subgroups of customers within a rate class (Companies Brief at 40, citing Exh. DPU-12-5).

Moreover, the Companies disagree with Cape Light Compact's argument that the Department should re-interpret Section 94I to mean that the ten-percent cap applies to the distribution increase to a customer class (Companies Brief at 40, citing Cape Light Compact Brief at 70). According to Eversource, this interpretation would limit the distribution revenue deficiency that any distribution company may claim and contravenes the earnings stability and continuity rate design principles (Companies Brief at 40). Further, the Companies argue that if a ten-percent cap is placed on the distribution increase, a company may not be made whole in any rate proceeding and may file base rate cases more frequently (Companies Brief at 40). Eversource contends that this scenario would result in financial implications and may threaten the integrity of its operations (Companies Brief at 40). For these reasons, the Companies argue that the Department should reject Cape Light Compact's interpretation of Section 94I (Companies Brief at 40).

iii. Revenue Increase Cap Allocation (Basic Service)

According to the Companies, TEC's, WMIG's and Cambridge's arguments to adopt the average twelve-month basic service pricing for determining bill impacts and to cap rate increases on reply brief are flawed, confused, and not appropriate under current market conditions (Companies Brief at 41; Companies Reply Brief at 29, 38, 47-48). Eversource maintains that it used the most recent basic service prices in its calculations (Companies Brief at 41, citing Exh. ES-RDP-1, at 40). According to the Companies, current trends indicate that Basic Service prices are increasing (Companies Brief at 41). Therefore, the Companies assert that it is more appropriate to use the most current basic service prices to determine the cap on overall bill increases beginning in January 1, 2018 rather than using a twelve-month average when basic service prices were lower (Companies Brief at 41). Further, Eversource maintains that the Department has stated that to "conform to Section 20 of the 2012 Energy Act a utility must calculate the total revenues generated by each rate class using the most recently effective rates." (Companies Brief at 41-42, citing D.P.U. 13-90, at 247-248).[25]

Moreover, Eversource maintains that the large C&I Basic Service fixed price for the first quarter 2017, which the Company used in its bill impact analyses for NSTAR Electric,

[25] In D.P.U. 13-90, the Department referred to An Act Relative to Competitively Priced Electricity in the Commonwealth as the 2012 Energy Act. Among other things, this Act established Section 94I. St. 2010, c. 209, § 20.

is consistent with the 2017 large C&I basic service prices for the year (Companies Reply Brief at 29, 38, 47-48). According to the Companies, the first quarter price that was used in bill impacts was greater than actual second quarter prices, but less than fourth quarter prices, and almost the same as third quarter prices (Companies Reply Brief at 29, 38, 47-48). Therefore, the Companies argue that there is no need to revise the Basic Service prices used in the bill impact calculations (Companies Reply Brief at 29, 38, 47-48). Accordingly, Eversource contends that its approach is consistent with Department precedent, and that the Department should reject these intervenors' recommendations (Companies Brief at 40-41).

iv. Availability Provisions

In response to Cape Light Compact's argument that a longer threshold than three months should be used to evaluate demand for C&I rate class availability, the Companies argue that Cape Light Compact's recommended twelve-month threshold for availability creates less homogenous rate classes (Companies Brief at 42). Eversource notes that a twelve-month threshold for rate classification means that a customer qualifies for a smaller C&I rate if there is one month that the customer's demand falls below the threshold (Companies Brief at 42). Eversource argues that significantly different customers could be grouped together using a twelve-month period, such as (i) one customer with eleven months of 500 kW and one month below 100 kW and (ii) another customer with 10 kW every month (Companies Brief at 42). According to Eversource, this scenario allows a large C&I customer with eleven months of 500 kW demand to take service on a smaller C&I rate class than appropriate (Companies Brief at 42). Accordingly, Eversource contends that a three-month threshold more appropriately establishes the size of a customer and its requirements for service (Companies Brief at 42-43).

v. Seasonal Rates

Eversource disagrees with Cape Light Compact's recommendation that it should retain seasonal rates because of the tourism industry in Commonwealth Electric's service territory (Companies Brief at 43). Eversource maintains that its other service territories have successful seasonal tourism industries, and those customers do not need and/or take service on seasonal rates (Eversource Brief at 43). Further, the Companies allege that low-use seasonal customers will receive bill decreases or minimal increases (Companies Brief at 43, citing Exh. ES-RDP-2, Sch. RDP-9 (East)). According to the Companies, eliminating seasonal rates spreads cost recovery evenly over an annual period and is beneficial to these customers (Companies Brief at 43).

vi. Education Plan

Eversource maintains that there is a critical need to effectively communicate with its customers on the implementation of the proposals in this case (Companies Brief at 44; Companies Reply Brief at 25). According to the Companies, they developed a comprehensive communications and outreach plan prior to their filing in January (Companies Brief at 44; Companies Reply Brief at 25). Further, Eversource states its commitment to promote its energy efficiency programs to educate customers on savings strategies (Companies Brief at 44, citing Exh. DPU-12-12; Companies Reply Brief at 25). Eversource intends to further develop its communication and outreach plan after January 1, 2018, because it cannot do so without knowledge of the Department's decisions in this proceeding (Companies Brief at 44; Companies Reply Brief at 25).

vii. Separate Proceeding

The Companies maintain that a separate proceeding to consider new rate designs, as UMass requests, is not necessary (Companies Reply Brief at 37). The Companies assert that there is adequate evidence in the current proceeding for the Department to issue a decision on rate design consistent with the rate design principles and the Commonwealth's policy goals (Companies Reply Brief at 37).

5. Analysis and Findings

a. Introduction

In ruling on the Companies' rate design proposals, the Department considers its rate structure goals: to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 15-155, at 455; D.P.U. 15-80/D.P.U. 15-81 at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341.

b. Cost Allocation

The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated, to the extent possible, based on equalized rates of return. Boston Gas Company, D.T.E. 03-40, at 384 (2003); D.T.E. 02-24/25, at 256; The Berkshire Gas Company, D.T.E. 01-56, at 139 (2002); D.P.U. 92-210, at 214.

Eversource's 2018 revised rate design proposal is based on a multiple legacy rate class ACOSS using a consolidated revenue requirement; its 2019 rate design proposal is based on a consolidated and aligned rate class ACOSS using a consolidated revenue requirement (Exh. DPU-56-9, at 1 (Supp.); RR-DPU-49, Atts. (A)-(E), (J)). The Department approved the corporate consolidation of NSTAR Electric and WMECo in the D.P.U. 17-05 Order. D.P.U. 17-05, at 43-44. Moreover, the Companies already operated under the supervision of a common management team and incur costs on a shared basis (Exh. ES-RDP-Rebuttal-1, at 13 (August 22, 2017)). Accordingly, the Department agrees with the Companies that maintaining separate revenue requirements does not represent a more appropriate allocation of costs. Therefore, the Department finds it appropriate for the Companies to allocate a consolidated revenue requirement of the combined Companies for the purposes of designing base distribution rates.[26] The Companies' proposed allocation method satisfies the Department's rate structure goal of fairness.

Further, Section 94I provides:

> In each base distribution rate proceeding conducted by the [D]epartment under [G.L c. 164, § 94], the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost allocation method for any [one] customer class would be more than [ten percent], the [D]epartment shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

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26 See Schedule 10 below.

The ten-percent cap meets our rate structure goals of fairness and continuity by ensuring that: (1) the final rates to each rate class represent or approach the cost to serve that class; (2) the limited level of cost subsidization created by the cap will not unduly distort rate efficiencies; and (3) the magnitude of change to any one class is contained within reasonable bounds. D.P.U. 13-90, at 247; D.P.U. 13-75, at 362. The Department has interpreted the requirements of Section 94I such that no rate class shall receive an increase greater than ten percent of the total revenues generated by each rate class. D.P.U. 13-90, at 247; D.P.U. 13-75, at 338, 363. Further, the Department has found it appropriate to include cost increases associated with costs collected through reconciling mechanisms in the application of the ten percent cap, if those costs increases were included in the company's rate case filing. D.P.U. 14-150, at 398.

Eversource argues that the statutory language does not indicate that the ten-percent cap be applied to individual customers, subsets, or subgroups of customers within a rate class (Companies Brief at 40, citing Exh. DPU-12-5). The Department has not applied Section 94I in a rate case proceeding where a company has proposed to eliminate existing rate classes and create a new set of rate classes for its entire customer base. Eversource's interpretation of Section 94I assumes that the group of customers taking service in the future on the proposed consolidated rate classes actually were taking service on these proposed consolidated rate classes in the test year (Exhs. ES-RDP-2, Sch. RDP-4 (East); ES-RDP-2, Sch. RDP-4 (West); DPU-12-5). The Companies imputed "current revenue" using test billing determinants from the group of customers on the proposed consolidated rate class

(Exhs. ES-RDP-2, Sch. RDP-4 (East); ES-RDP-2, Sch. RDP-4 (West)). Then, the Companies calculated the difference between "current revenue" and proposed revenue based on the proposed consolidated rate classes (see Exhs. ES-RDP-2, Sch. RDP-4 (East); ES-RDP-2, Sch. RDP-4 (West)). This method is based on the incorrect premise that the group of customers is currently taking service on the proposed consolidated rate class (see Exhs. ES-RDP-2, Sch. RDP-4 (East); ES-RDP-2, Sch. RDP-4 (West)).

The Companies maintain that their interpretation of the application of Section 94I is accurate (Exh. DPU-12-5). However, the Companies' interpretation results in some groups of customers transferring from legacy rate classes to the consolidated rate classes that, in reality, would experience an actual increase that is greater than Section's 94I cap of ten percent (RR-DPU-50, Att. (a)-(b) (compare current revenue to 2019 revenue, or 2018 revenue to 2019 revenue)). For example, Cambridge Electric Light Company customers moving from legacy Rate G-5 to consolidated Rate G-1 (non-demand) would be subject to a 16-percent total (class) revenue increase; Cambridge Electric Light Company customers moving from legacy Rate G-3 to consolidated Rate G-1 (demand) would be subject to a 35-percent total (class) revenue increase; Commonwealth Electric Company customers moving from legacy Rate G-4 to consolidated Rate G-1 (demand) and Rate G-2 would be subject to a 23-percent total (class) revenue increase and a 54-percent total (class) revenue increase, respectively; and Commonwealth Electric Company customers moving from legacy Rate G-6 to consolidated Rate G-3 would be subject to a 27-percent total (class) revenue increase (RR-DPU-50, Att. (b)). The Department finds that this result, with the confluence of legacy rate classes and consolidated rate classes, does not comply with Section 94I. Therefore, we find that the ten-percent cap shall apply to each group of customers currently on a legacy rate that are moving to the same aligned/consolidation rate.

Further, with respect to the application of Section 94I to reconciling rate revenue, the Department has stated that, for the Department to incorporate reconciling rate revenue updates into a rate design, we would be compelled to choose between (i) revenues generated from existing rates that soon will change and will no longer be representative and (ii) future revenues that cannot be determined with any level of precision. D.P.U. 13-75, at 357. The Department did not permit a company to update test year reconciling rate revenues for post-test year changes in reconciling rates outside the base rate case filing, since costs recovered through reconciling mechanisms are volatile and change frequently. D.P.U. 13-75, at 355. A company's rate design that results from a base distribution rate proceeding establishes long-term rate changes and should not encompass reconciling rate revenues that change annually or semi-annually. D.P.U. 13-75, at 355. The Department determined that including changes in reconciling rate revenues in rate design is not practical due to the frequency of a company's updates to its reconciling mechanism factors. D.P.U. 13-75, at 355.

Cambridge, TEC, and WMIG do not propose updates to the Basic Service prices used in the calculation of the ten-percent cap while the rate case proceeding is ongoing. Instead, Cambridge, TEC, and WMIG recommend the use of an annual average of Basic Service prices to determine total revenue that is subject to the ten-percent cap. Because Basic

Service prices change quarterly for some C&I customers and bi-annually for other customers, the Department finds that using the average annual basic service prices is a more representative value to determine the portion of Basic Service revenue in the calculation of the ten percent cap. Accordingly, the Department directs the Companies, in compliance with this Order, to use the annual average Basic Service prices for all rate classes to determine total revenue in the calculation of the ten-percent cap.[27]

c. Consolidation and Alignment

A utility's rate structure comprises the level and pattern of prices charged to specific customers for the use of utility services. D.P.U. 10-55, at 556. The specific rate structure of each rate class is a function of the cost to the utility of providing service to the rate class and of the design of rates calculated to recover the cost. D.P.U. 10-55, at 556. Rate classes are established based on the costs of serving different groups of customers. Boston Edison Company, D.P.U. 84-236-A, at 11 (1986).

To determine if the proposed rate consolidation should be allowed, we must consider whether it is consistent with our rate structure goals of simplicity, efficiency, continuity, fairness, and earnings stability. D.P.U. 10-55, at 556. Further, to ensure that our goals of efficiency, fairness, and earnings stability are not contravened, we will examine if the classes that are proposed to be consolidated have similar load characteristics. D.P.U 10-55, at 556. Finally, we will examine bill impacts at the rate class level to determine if our continuity goal is met. D.P.U. 10-55, at 556.

[27] See Schedule 10 below.

Consolidating rates will simplify Eversource's rate structure and, therefore, we find that it meets our simplicity goal (see, e.g., Exhs. ES-RDP-1, at 6-7, 54; DPU-18-6; RR-DPU-51, Att. (c) at 13-30). The proposed consolidation of rates across the Companies' service areas fully consolidates residential rates and begins Eversource's process to eventually consolidate the C&I rates of all its Massachusetts electric operations into a single set of rates. Eversource's reorganization efforts started to move in this direction with the consolidation of its reconciling rate filings submitted to the Department. See, e.g., NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource Energy, D.P.U. 15-122 (grid modernization plan); NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource Energy, D.P.U. 17-157 (annual reconciliation filing). Further, the Department approved the consolidation of their Terms and Conditions in the D.P.U. 17-05 Order. D.P.U. 17-05, at 729. As such, consolidation of Eversource's rates and tariffs represents a logical continuation of its reorganization efforts and would increase both administrative efficiency and customer understanding of the Companies' rate structure. D.P.U. 10-55, at 557.

In determining whether to allow the Companies to consolidate classes, the Department must consider whether the customers served by these rate classes have similar cost patterns. Commonwealth Electric Company, D.P.U. 88-135/151, at 199-200 (1989). In Boston Edison Company, D.P.U. 1720 (1984) at 136, the Department stated:

> The primary consideration in developing rate classes is that, given the cost-effective means of measuring demand and use, individual customers must be grouped so that the rates they pay are reasonably representative of the costs of serving them (fairness),

> and that the rate structure which does this remain simple enough to promote efficiency. The costs incurred in serving customers are essentially a function of the voltage level at which they are served and the times at which they demand electricity.

Accordingly, a rate class is a group of electric company customers with similar costs of service, which are primarily a function of customer load characteristics and voltage level. D.P.U. 88-135/151, at 199-200; D.P.U. 84-236-A at 11. The costs of serving, for the purposes of determining rate classes, are: (1) marginal costs unitized by function and classification; and (2) embedded costs, also on a unitized basis. D.P.U. 88-135/151, at 200. The Department previously has held that rate classes may be consolidated when unit embedded and marginal costs do not differ significantly among individual rate classes. D.P.U. 88-135/151, at 200; Cambridge Electric Light Company, D.P.U. 87-221-A at 125 (1988); Colonial Gas Company, D.P.U. 86-27-A at 72-73 (1988); New England Telephone and Telegraph Company, D.P.U. 1731-C at 22-25 (1987); Boston Edison Company, D.P.U. 85-266-A/85-271-A at 236 (1986).

In the past, Department relied on marginal cost pricing to set rates. However, it is the Department's current ratemaking preference to set prices based on embedded costs to encourage energy efficiency, rather than base distribution rates based on the results of a marginal cost study (see Exhs. DPU-12-19; DPU-18-2). D.P.U. 15-155, at 473-490; D.P.U. 15-80, at 317-325. Therefore, the Department will compare unit embedded costs among various existing rate classes. A comparison of unit embedded costs between existing rate classes is used to determine whether a rate consolidation would result in the unfair subsidization of one class at the expense of another class.

i. Residential Rate Consolidation and Alignment

Based on these considerations, the residential unit embedded costs were derived from the Companies' ACOSS, below.

Residential Embedded Costs[28]

	Boston Edison Company	**Cambridge Electric Light Company**	**Commonwealth Electric Company**	**WMECo**	**Consolidated Rate Class**
Consolidated Residential (Rate R-1/R-2)	**R-1/R-2/R-4**	**R-1/R-2/R-5**	**R-1/R-2/R-5/ R-6**	**R-1/R-2**	**R-1/R-2**
$demand/kWh	0.0495	0.0479	0.0455	0.0431	0.0462
kWh	3,722,940,960	178,464,144	1,835,322,337	1,088,393,372	6,825,120,813
Percent difference from consolidated class	7.14	3.68	-1.52	-6.71	
Consolidated Residential Heating (Rate R-3/R-4)	**R-3/R-2**	**R-3/R-4/R-6**	**R-3/R-4**	**R-3/R-4**	**R-3/R-4**
$demand/kwh	0.0586	0.0770	0.0574	0.0528	0.0550
kWh	441,337,021	11,990,613	237,632,544	222,331,736	913,291,914
Percent difference from consolidated class	6.55	40.00	4.36	-4.00	

28 Source: RR-DPU-49, Atts. (B)-(E), (J).

The Department finds that the differences in unit embedded costs among Boston Edison Company's, Cambridge Electric Light Company's, Commonwealth Electric Company's, and WMECo's residential customer classes are within an acceptable range, and that the consolidation of these rate classes does not contravene the Department's rate design goals. D.P.U. 88-135, at 201-202. Accordingly, the Department allows the Companies' proposed consolidation of its residential distribution rates across all four legacy companies.

The Department, however, is concerned with the difference in unit embedded costs between the Cambridge Electric Light Company's residential heating rate classes and the consolidated residential heating rate class. Since the embedded cost of serving Cambridge Electric Light Company customers is higher than that of other customers, consolidation would lead to the subsidization of Cambridge Electric Light Company's customers at the expense of the remaining residential customers. However, Cambridge Electric Light Company's residential heating consumption represents approximately only 1.3 percent of total residential electric heating load. Therefore, the Department finds that any subsidization would be minimal. Further, the Department finds that the differences in unit embedded costs among Boston Edison Company's, Cambridge Electric Light Company's, Commonwealth Electric Company's, and WMECo's residential heating rate classes are within an acceptable range, and that the consolidation of these rate classes does not contravene the Department's rate design goals. D.P.U. 88-135, at 201-202. Accordingly, the Department allows the Companies proposed consolidation of its residential heating distribution rates across all four legacy companies.

Additionally, 98 percent of NSTAR Electric's residential customers will not see a change in their rate structure, and WMECo's residential customers will see very minimal changes in their rate structure as a result of rate consolidation (Exhs. ES-RDP-3 (ALT1), Sch. RDP-2 (East); ES-RDP-3 (ALT1), Sch. RDP-2 (West)). In addition, the Department has examined the class bill impacts resulting from the proposed rate increase assuming rate and revenue requirement consolidation (RR-DPU-50, Att. (a); RR-DPU-50, Att. (e) at Exhs. ES-RDP-2 (ALT1), Sch. RDP-4). The consolidated rate classes were capped using the statutorily mandated ten percent on total revenue increase and with the use of the 200-percent distribution rate cap (Exhs. ES-RDP-2 (ALT1), Sch. RDP-4). We find that the class bill impacts created by the consolidation of Eversource's residential rates satisfy our rate continuity goal. Therefore, we find the bill impacts resulting from the consolidation to be within an acceptable range.

Moreover, although the Companies proposed to implement consolidated residential rates for effect January 1, 2019, the Companies acknowledge that it is capable of implementing the change for residential rates effective February 1, 2018 without any adverse bill impacts to customers (Tr. 17, at 3478-3479). Further, the Companies' initial rate design proposal provided for the implementation of aligned residential rate changes only once, effective January 1, 2018 (Exh. ES-RDP-1, at 49). Accordingly, the Department directs the Companies to implement consolidated residential rates for effect February 1, 2018.[29] In

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29 In approving the Companies' proposal to consolidate its residential rates, the Department allows the Companies' to eliminate residential inclining block rates,

doing so, the Department directs the Companies to rely on the target revenue for Rate R-1/Rate R-2 and Rate R-3/Rate R-4 using the results of the consolidated ACOSS (RR-DPU-49, Att. (J)). The Department will evaluate continuity of the rate design and consider specific bill impacts in Section IV.K below.

ii. C&I Rate Consolidation and Alignment

Based on the considerations above, the Department evaluates C&I unit embedded costs derived from the Companies' ACOSS for customers moving to aligned Rate G-1, for simplicity, below.

C&I Embedded Costs[30]

Legacy Company	Legacy Rate Class	Demand ($/kWh)	Percent Difference
Boston Edison Company	**G-1/T-1**	0.0311	-9.89
	G-2/T-2	0.0332	-3.61
	G-3	0.0207	-39.90
Cambridge Electric Light Company	**G-0/G-1/G-6**	0.0326	-5.32
	G-2	0.0304	-11.91
	G-3	0.0238	-30.87
	G-4	0.0257	-25.38
	G-5	0.0633	83.54
Commonwealth Electric Company	**G-1/G-7**	0.0387	12.17
	G-2	0.0307	-10.99
	G-3	0.0251	-27.20
	G-4	0.0457	32.47
	G-5	0.0665	92.93
	G-6	0.0542	57.36
Proposed Aligned Rate	**G-1 EMA**	0.0345	

residential seasonal rates, residential optional TOU rates, and residential controlled water heating rates.

30 Source: RR-DPU-49, Atts. (B)-(E), (J).

The Department is concerned with the difference in unit embedded costs between the legacy rate classes and NSTAR Electric's proposed aligned Rate G-1, which vary between negative 40 percent and 93 percent.

Further, the Department must find that, pursuant to Section 94, the Companies' proposed consolidated C&I tariffs are consistent with the public interest. D.P.U. 13-90, at 265; D.P.U. 09-39, at 302; Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 189 (2009). One component of this standard, applicable to tariff construction, requires that a proposed tariff have sufficient detail to explain the basis for the rate to be charged for the offered service. Boston Gas Company, D.P.U. 92-259, at 47-48 (1993); Dedham Water Company, D.P.U. 13271, at 10 (1961). According to the Companies' mitigation plan, only certain customers that Eversource deems eligible will receive a mitigation discount. The Companies analyzed all C&I customers with twelve months of 2015 billing data[31] in the billing database to design their revised mitigation plan and to determine which customers were eligible to receive a mitigation discount (Exh. DPU-63-6, at 2 n.4 (Supp.)). According to the Companies' analysis, 790 NSTAR Electric and 79 WMECo C&I customers would experience pre-mitigation monthly bill impacts of greater than 15 percent or $360 (Exh. DPU-63-6, at 2 (Supp.)). Further, specific customers within a legacy rate class that Eversource deemed eligible for a proposed mitigation discount would be assigned a rate code

[31] Eversource stated that it did not anticipate significant changes to the 2015 billing determinants for customers that were included in its analysis (Exh. DPU-68-4). However, Eversource stated that it intended to perform an additional review of accounts as of September 1, 2018 to ascertain whether or not there are additional accounts in need of mitigation that were not previously identified (Exh. DPU-68-4).

for the discount (Exh. DPU-68-1). For example, the Companies determined that certain Boston Edison Rate T-2 customers moving to aligned Rate G-1 Demand are eligible to receive a discount of 14.5 percent on their demand and energy charges in 2019 (Exhs. DPU-63-6, Att. (c) at 3 (Supp.1); DPU-68-1). Eversource plans to establish a new rate code for aligned Rate G-1 Demand in its billing system to determine which customers are assigned to the 14.5-percent discount (Exh. DPU-68-1). Those customers who are not mitigation eligible would be assigned a different rate code under the aligned Rate G-1 Demand (Exh. DPU-68-1). Eversource's proposed Rate G-1 tariff does not identify a rate code for each legacy rate class that Eversource determines is eligible for a discount (RR-DPU-51, Att. (c) at 13-16). Therefore, the Department finds that the Companies' proposed tariffs do not provide sufficient detail to explain the basis by which customers are mitigation eligible and under which rate or discount that they will be charged.

Moreover, absent the Companies' mitigation plan, some C&I customers would experience bill impacts of more than 100 percent (RR-DPU-50, Att. (g) at Exhs. ES-RDP-4 (ALT1), Sch. RDP-4 (East), at 7, 15, 27, 29, 39, 41, 43; ES-RDP-4 (ALT1), Sch. RDP-5 (East), at 17; ES-RDP-4 (ALT1), Sch. RDP-6 (West), at 1). While the mitigation plan proposes to phase in large increases to some customers, these customers still will incur successive bill increases for up to five years, of over 100 percent of their current rates. Further, Eversource's proposed mitigation plan sets out a series of discounts for different legacy rate classes that will change annually for five years. The Companies' proposal does not include annual filings or any other means for the Department to evaluate the annual mitigation discounts other than the preapproval of the plan in this case (Exh. DPU-18-9).

Based on the disparity in the embedded costs, our findings regarding the allocation of the revenue requirement increase to certain legacy rate classes above the Section 94I ten-percent cap, and our findings above regarding tariff design and mitigation, the Department declines to approve Eversource's proposal to align and consolidate C&I rate classes at this time. Accordingly, the Department finds in the instant case that the legacy C&I rate classes shall remain in place for rates effective February 1, 2018.[32]

The Department recognizes and supports the Companies' commitment to balance the Department's rate design principles in their rate design consolidation and alignment proposal, and generally supports the goal of consolidating Eversource's C&I rate structure. In the long-run, customers will benefit from rate consolidation and alignment because it will give the Companies greater flexibility to address policy goals and customer needs on a modernized electric service offerings, while also making it easier for customers to understand the charges and costs represented on their bills (Exh. DPU-18-14). However, the Department cannot ignore our obligation to balance rate design principles of simplicity, fairness, and continuity

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32 Therefore, with our approval of C&I rates only for effect February 1, 2018, the Department will not address Cambridge's, FEA's, WMIG's, and TEC's argument regarding erratic base distribution rate changes, where the 2018 rate would have been higher than the 2019 rate, because the Department has approved the C&I rates only for effect February 1, 2018. Further, Cape Light Compact's arguments regarding availability provisions and the retention of seasonal rates are rendered moot with the Department's decision to not approve Eversource's proposal to align and consolidate C&I rate classes at this time.

in achieving this consolidation/alignment goal. Therefore, the Department directs the Companies to undertake a gradual implementation of a consolidated and aligned rate design for C&I customers to ameliorate large bill impacts without a multi-year subsidy plan, to improve unclear tariffs, and to comply with Section §94I. The Department encourages Eversource to provide for a more gradual plan for consolidation and alignment either through its next general rate filing or through a revenue neutral rate design filing(s). The Department directs the Companies to focus on customer bill impacts and to ensure that any proposed rate design is transparent.

iii. Street Lighting

Based on these considerations, the street lighting unit embedded costs were derived from the Companies' ACOSS, below.

Street Lighting Embedded Costs[33]

Company	Rate Class	Demand ($/kWh)	Percent Difference
Boston Edison	SL	$0.03390	-7.88%
Cambridge Electric Light	SL	$0.03560	-3.26%
Commonwealth Electric	SL	$0.03560	-3.26%
Proposed Aligned Rate	**EMA SL**	$0.03680	
WMECo	SL	$0.03430	9.91%
Proposed Aligned Rate	**WMA SL**	$0.03770	

The Department finds that the differences in unit embedded costs between Boston Edison Company's, Cambridge Electric Light Company's, and Commonwealth Electric

[33] Source: RR-DPU-49, Atts. (B)-(E), (J)

Company's street lighting rate class, and the proposed aligned rate street lighting class are within an acceptable range. Further, the Department finds that the difference in unit embedded cost between WMECo's street lighting rate class, and the proposed aligned rate street lighting class are within an acceptable range. Therefore, the Department finds that the consolidation of these rate classes for NSTAR Electric and WMECo does not contravene the Department's rate design principles. See D.P.U. 88-135, at 201-202. Accordingly, the Department allows the Companies to consolidate its street lighting distribution rates across all four legacy companies.

Moreover, although the Companies proposed to implement consolidated street lighting for effect January 1, 2019, the Companies acknowledge that they are capable of implementing the change for rates effective February 1, 2018 without any adverse bill impacts to customers (Tr. 17, at 3480). Further, the Companies' initial rate design proposal provided for implementation of aligned street lighting rate changes only once, effective January 1, 2018 (Exh. ES-RDP-1, at 49-50). Accordingly, the Department directs the Companies to implement consolidated street lighting rates for effect February 1, 2018. In doing so, the Department directs the Companies to rely on target revenue for street lighting using the results of the consolidated ACOSS (RR-DPU-49, Att. (J)). The Department will evaluate continuity of the rate design and consider specific bill impacts in Section IV.K below.

d. Conclusion and Directives

In setting revenue targets for the legacy C&I rate classes, the Department directs Eversource, in its compliance filing, to rely first on its consolidated ACOSS to determine the residential rate class and street lighting revenue targets at equalized rates of return, before the application of the ten-percent and 200-percent caps (see RR-DPU-50, Att. (e), at Exh. ES-RDP-2, Sch. RDP-4). The Department directs Eversource to allocate the remaining revenue requirement at equalized rates of return to its legacy C&I rate classes using the same method that the Companies proposed in their revised rate design proposal (RR-DPU-50, Att. (f), at Exhs. ES-RDP-3 (ALT1), Sch. RDP-4, at 1 (East); ES-RDP-3 (ALT1), Sch. RDP-4 (West)).[34] The Department addresses rate class specific bill impacts for C&I legacy rate classes in Section IV.K below.

The Department's long-standing policy regarding the reallocation of class revenue requirements that exceed a cap is that revenue should be allocated to those rate classes that do not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return. D.T.E. 03-40, at 384; D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-210, at 214. Moreover, the Department recently directed National Grid and Fitchburg Gas and Electric Light Company to allocate the revenue requirement in excess of the ten-percent rate cap to those rate classes that did not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return instead of test year distribution revenues. D.P.U. 15-155, at 392-393; D.P.U. 15-80/D.P.U. 15-81, at 302. For these

[34] See Schedule 10 below.

reasons, and to advance the rate goals of fairness and efficiency, the Department directs Eversource in its compliance filing to allocate the approved revenue requirement that exceeds the ten-percent rate cap to those rate classes that did not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return, consistent with the Companies' revised rate design proposal (see RR-DPU-50, Att. (e)-(f) at Exhs. ES-RDP-2 (ALT1), Sch. RDP-4; ES-RDP-3 (ALT1), Sch. RDP-4 (East); ES-RDP-3 (ALT1), Sch. RDP-4 (West)).

The Department notes that allocating the revenue requirement that exceeds the ten-percent rate cap based on revenue requirements at equalized rates of return continues to result in a significant rate increase for several rate classes, which contravenes our continuity goal. Consequently, the Department directs Eversource to limit the distribution rate increase for these rate classes to 200 percent of the overall distribution rate increase, and to allocate the remaining revenue requirement to the uncapped rate classes based on the ratio of their class revenue requirement at equalized rates of return to the sum of the class revenue requirement at equalized rates of return for all uncapped rate classes (see RR-DPU-50, Att. (e)-(f) at Exhs. ES-RDP-2 (ALT1), Sch. RDP-4; ES-RDP-3 (ALT1), Sch. RDP-4 (East); ES-RDP-3 (ALT1), Sch. RDP-4 (West)).

The Department has reviewed the Companies' ACOSS, and the Department finds that it is reasonable and consistent with Department precedent. D.P.U. 15-155, at 394-395; D.P.U. 15-80/D.P.U. 15-81, at 303, 309; D.P.U. 13-90, at 240-241; D.P.U. 11-01/D.P.U. 11-02, at 434-437. Accordingly, we accept the Companies' ACOSS as proposed, with the aforementioned changes in this section and in Section IV.C above. The Department directs Eversource to rerun its ACOSS for submission in its compliance filing to allocate its costs and expenses in excess of the ten-percent cap and 200-percent cap as approved in this Order.

Further, the Department addresses the necessity of a separate proceeding and an education plan in the MMRC section.

E. MMRC

1. Introduction

On April 11, 2016, Governor Baker signed into law Chapter 75 of the Acts of 2016, An Act Relative to Solar Energy ("Act"). Among other things, the Act adds G.L. c. 164, § 139(j), which gives the Department the authority to consider proposals for an MMRC. St. 2016, c. 75, § 9. The purpose of the MMRC is for all distribution company customers to contribute to the fixed costs that ensure the reliability, proper maintenance, and safety of the electric distribution system. G.L. c. 164, § 139(j). The Department may approve an MMRC that: (1) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (2) does not excessively burden ratepayers; (3) does not unreasonably inhibit the development of Class I, Class II, and Class III net metering facilities; and (4) is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system. G.L. c. 164, § 139(j). In addition, MMRC proposals shall be filed with the Department in: (1) a distribution company's base distribution rate proceeding; or (2) a revenue neutral rate design filing that is supported by appropriate cost of service data across all rate classes. G.L. c. 164, § 139(j).

Any MMRC approved by the Department must take effect no later than December 31, 2018. G.L. c. 164, § 139(j). The Department "may only approve a proposal for a monthly minimum reliability contribution after the aggregate nameplate capacity of installed solar generating facilities in the [C]ommonwealth is equal to or greater than 1,600 megawatts"("MMRC Date"). G.L. c. 164, § 139(j). On September 8, 2017, the Department certified that the MMRC Date has been reached. Net Metering Rulemaking, D.P.U. 16-64-G at 20 (September 8, 2017).

2. Companies Proposal

Eversource proposes to implement an MMRC for residential and C&I customers that are enrolled in the Companies' net metering tariffs (Exh. ES-RDP-1, at 85). Eversource intends to apply the MMRC only to net metering host customers, including low-income host customers, and not to accounts that are allocated net metering credits via Schedule Z (Exhs. ES-RDP-1, at 85; DPU-10-1).[35] As of 2015, the Companies provided net metering

[35] Each electric distribution company has an interconnection tariff, known as Standards For Interconnection Of Distributed Generation. See Fitchburg Gas and Electric Light Company d/b/a Unitil - M.D.P.U. No. 269; Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid – M.D.P.U. No. 1320; NSTAR Electric Company d/b/a Eversource Energy – M.D.P.U. No. 162D; Western Massachusetts Electric Company d/b/a Eversource Energy – M.D.P.U. No. 1039G. Each interconnection tariff sets forth the process and requirements for an interconnecting customer to connect a generating facility to the Electric Distribution Company's electric power system, including discussion of technical and operating requirements, metering and billing options, and other matters. Schedule Z to the

services to approximately 1.4 percent of its customers (19,415 host customers out of a total of 1,395,788 customers) (Exhs. DPU-10-2, Att.; AG-1-2(7)(j) at 171, Cell F10; AG-1-2(7)(p) at 167, Cell F10). Eversource states that under the MMRC, net metering customers retain net metering credits for their surplus production, which customers can apply to offset their electric bills (Exhs. ES-RDP-1, at 97; DPU-10-5; DOER-5-4, at 1). Eversource further states that the MMRC does not affect renewable energy credits or other incentives customers may receive (Exh. ES-RDP-1, at 97).

To implement the MMRC, Eversource proposes to: (1) install at customer locations demand meters that measure maximum billing cycle demand in kWs and meters that measure energy delivered and received in kWhs for customers charged the MMRC; and (2) update its billing system to incorporate the monthly demand charge (Exhs. ES-RDP-1, at 98; DPU-10-4, at 1-2). Eversource proposes to apply the MMRC to new residential and C&I net metering customers with an in-service date on or after January 1, 2019 (Exh. ES-RDP-1, at 91).[36]

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interconnection tariff, which is completed by or on behalf of a host customer, contains information regarding the host customer and the generating facility necessary to receive net metering services from the electric distribution company.

36 In its initial rate design proposal, Eversource proposed applying the MMRC to new residential net metering customers with an in-service date on or after January 1, 2018 (Exh. ES-RDP-1, at 91). In its revised rate design proposal, Eversource proposes to delay the application of the MMRC to new residential net metering customers by one year, to January 1, 2019 (Exh. DPU-56-9, at 8 (Supp.)). This shift in the effective date is the only change to the MMRC that Eversource proposes in its revised rate design proposal (Exh. DPU-56-9, at 8 (Supp.)). Eversource also clarifies that it does not propose to apply the MMRC to net metering customers that expand an existing

The proposed MMRC rate consists of a customer, demand, and, where applicable, volumetric charge (Exh. ES-RDP-1, at 85). Eversource states that rates for all other components of service will be the same as for all other customers within the relevant class (Exh. ES-RDP-1, at 85). Eversource maintains that the MMRC for each class is designed on a revenue neutral basis to the otherwise applicable distribution rate, based on the target distribution revenues assigned to the applicable rate class in the ACOSS (Exh. ES-RDP-1, at 86).

Under the MMRC, Eversource proposes to set the customer charge for each rate class equal to the full unit customer cost (Exhs. ES-RDP-1, at 86; DPU-10-6, at 2). Eversource asserts that this approach separates customer costs from distribution system costs, and assures that each net metering host customer is responsible for its share of customer costs that would otherwise be shifted to other customers if included in a volumetric charge (Exhs. ES-RDP-1, at 86; DOER-2-1).

Eversource states that it developed a volumetric charge and kilowatt charge for the MMRC using the allocated minimum distribution system costs from the ACOSS and the individual customer monthly peak demands of all customers within each rate class (Exh. ES-RDP-1, at 86). Eversource proposes that the demand component of the bill for the MMRC for residential customers be calculated based on the highest measured 15-minute demand interval within a billing cycle; for C&I customers the demand component of the bill

facility (i.e., a net metering facility with an in-service date before January 1, 2019) (Exh. DPU-10-10).

will be calculated as described in the tariff for each rate class (Exhs. DPU-46-11; AC-1-14; AG-48-2; Tr. 16, at 3255).

For the residential rate classes, Eversource states that it calculated a volumetric rate to achieve revenue neutrality within the rate class (Exh. ES-RDP-1, at 86). For the C&I rate classes, Eversource proposes to include the MMRC as part of the total demand charge for each class, and, to the extent that the rate design of a class includes a volumetric charge (e.g., Rate G-1), Eversource calculated an average volumetric rate based on the proposed total per-kWh revenue for that class (Exh. ES-RDP-1, at 86-87).

Eversource is not proposing an MMRC for the proposed consolidated rate classes Rate G-3 and Rate G-4 (Exh. DPU-46-10). Eversource maintains that the demand charges in those rates are sufficient to cover the costs reflected in the Rate G-1 and Rate G-2 MMRC rates (Exh. DPU-46-10). In addition, Eversource is not proposing to offer an optional TOU rate to C&I net metering customers charged the MMRC (Exhs. AC-1-20; DPU-56-14).[37] The proposed MMRC rates for each rate class are summarized in the table below:

37 Eversource clarifies that existing C&I net metering customers with installations by January 1, 2019 may elect to take service under the proposed optional G-5 TOU rate (Exhs. AC-1-19; AC-1-20).

Summary of Proposed MMRC Rates[38]

MMRC Rate Component	R-1/R-2	R-3/R-4	G-1 EMA	G-1 WMA	G-2 EMA	G-2 WMA
Customer Charge ($/month)	10.88	13.89	19.44	23.04	120.89	52.87
Demand Charge ($/kW)	2.21	2.71	5.16	7.75	6.02	7.58
Distribution Energy Charge ($/kWh)	0.03056	0.02085	0.01837	0.00658	0.01940	0.00827

Eversource maintains that as part of its overall communications plan, it proposes to educate residential customers about the demand charge under the MMRC (Exh. DPU-10-7). Eversource proposes to share information about net metering rates, including the MMRC, with developers who work regularly with residential net metering customers as part of the distributed generation workshops that Eversource regularly conducts (Exh. DPU-10-7). In addition, Eversource intends to provide pricing information for customers on its website, with illustrations and examples, and to train the Companies' representatives who respond to distributed generation requests on this information (Exhs. DPU-10-7; DPU-46-17).

3. Positions of the Parties

a. Statutory Requirements

i. Equitable Allocation of Fixed Costs

(A) Intervenors

Intervenors argue that Eversource does not meet the requirement of having an MMRC that equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption because the Companies: (1) have not demonstrated that a cost-shift

38 Source: RR-DPU-50, Att. (i) at Exh. ES-RDP-6 (ALT1), Sch. RDP-1.

exists between net metering and non-net metering customers; (2) did not consider the benefits provided by net metering facilities; and/or (3) did not perform a separate cost allocation study for distributed generation customers within each rate class.

Several intervenors argue that the Companies have not demonstrated that there is a cost-shift from net metering to non-net metering customers when it comes to contributing to the fixed costs of the distribution system (Cape Light Compact Brief at 46-47; NECEC Brief at 25; NECEC Reply Brief at 5; Sunrun and EFCA Reply Brief at 6; Vote Solar Brief at 5-6). In particular, several intervenors maintain that Eversource did not conduct a cost of service analysis or any other reasonable analysis with quantitative record evidence that would quantify the amount of costs attributable to distributed generation customers (Acadia Center Brief at 17; Cape Light Compact Brief at 44, 52; Cambridge Brief at 11; NECEC Brief at 25-27; NECEC Reply Brief at 7; Sunrun and EFCA Brief at 7; Vote Solar Brief at 6; Vote Solar Reply Brief at 3). Cape Light Compact, Cambridge, Sunrun and EFCA, and Vote Solar contend that Eversource only provides calculations of displaced distribution revenues ("DDR") as proof of subsidization, and that these DDR alone are not sufficient (Cape Light Compact Brief at 48; Cambridge Brief at 11; Sunrun and EFCA Brief at 5; Sunrun and EFCA Reply Brief at 6; Vote Solar Brief at 5; Vote Solar Reply Brief at 3). Further, Cape Light Compact and Sunrun and EFCA argue that the fact that one of Eversource's two operating companies is not yet decoupled is not a valid argument, and it does not transform DDR under a given rate design into a complete accounting of costs and benefits attributable to distributed generation customers in the NSTAR Electric service territory (Cape Light Compact Reply Brief at 11; Sunrun and EFCA Reply Brief at 6-7).

Acadia Center contends that Eversource inappropriately focuses on a short-run fixed cost concept for cost shifts, when the rate design principle of efficiency is based on long-run costs and benefits (Acadia Center Reply Brief at 3). Acadia Center maintains that this improper focus is why the Companies' purported DDR should not be dispositive to the Department's determination (Acadia Center Reply Brief at 3). Acadia Center disagrees with Eversource that as customers' change their behavior by exercising control over their bills, for example, through the installation of distributed generation, the result is an "intra-class inequity" where costs are shifted to other customers within that class who have difficulty controlling their bills (Acadia Center Reply Brief at 6). Acadia Center argues that customers' responses to the price signals and control over their bills should be viewed as progress – not an inequity that must be reconciled through mandatory charges (Acadia Center Reply Brief at 6).

Several intervenors maintain that the Companies do not meet the equitable allocation requirement because Eversource has not considered the benefits associated with net metering facilities (Acadia Center Brief at 17; Cape Light Compact Brief at 47-48; Cambridge Brief at 11; NECEC Brief at 26, 29; NECEC Reply Brief at 6; Sunrun and EFCA Brief at 6; Sunrun and EFCA Reply Brief at 6; Vote Solar Brief at 5, 7, citing D.P.U. 15-155, at 458; Vote Solar Reply Brief at 4). Cape Light Compact argues that examples of the benefits to be considered are: (1) avoiding the need to make utility investments to serve additional load,

(2) reducing energy and capacity purchases, and (3) reducing the cost of compliance with the Global Warming Solutions Act (Cape Light Compact Brief at 48-49). Cape Light Compact disagrees with the Companies' argument that the random locations of distributed generation systems do not result in systematic benefits to the distribution system over the long-run (Cape Light Compact Reply Brief at 11).

Finally, Cape Light Compact argues that Eversource's minimum size method takes costs classified as demand-related and shifts recovery of a portion of them from volumetric rates to a demand charge for new net metering customers (Cape Light Compact Brief at 52). Cape Light Compact also contends that the proposed MMRC demand charge fails to equitably allocate costs because the Companies allocate the costs based on each rate class' contribution to peak demand but do not perform a separate cost allocation study for distributed generation customers within that rate class (Cape Light Compact Brief at 52).

(B) Companies

Eversource disagrees with Cape Light Compact, NECEC, Sunrun and EFCA, and Vote Solar regarding the assertion that the Companies have not demonstrated that net metering imposes a cost to the Companies (Companies Brief at 52). The Companies argue that DDR is approximately $8 million per year and growing (Companies Brief at 52; Companies Reply Brief at 22, 39, 42, citing Exhs. DPU-10-12; DPU-46-9; SREF-1-28). The Companies maintain that the source of the DDR is the net metering recovery surcharge ("NMRS") annual filing (Companies Brief at 52; Companies Reply Brief at 39). In response to the argument that evidence of DDR alone is insufficient to demonstrate cost shifting from net metering customers to non-net metering customers, Eversource contends that NSTAR Electric is not currently decoupled and does track this information, unlike National Grid (Companies Brief at 53). In response to the intervenors' argument that there is a lack of analysis or informative reports to prove the cost shift, the Companies argue that the DDR calculations are far more granular than any report provided by decoupled distribution companies (Companies Reply Brief at 42).

The Companies argue that the issue of benefits confuses the issue of whether net metering customers are displacing their usage thereby reducing the amount that they pay to Eversource for the distribution service (Companies Brief at 54). First, Eversource maintains that any presumed benefits are long-run in nature and would not offset the Companies' short-run fixed costs (Companies Brief at 54). Second, Eversource contends that the installation of distributed generation is driven by customer financial incentives rather than by system planning, and that the installations do not necessarily result in benefits to the distribution system over the long-run (Companies Brief at 54).

Finally, Eversource maintains that, to ensure equitable allocation of costs and to avoid any question about cost causation relative to volumetric consumption, the Companies have allocated only a portion of demand-related costs by calculating a minimum system cost for each rate class (Companies Brief at 56, citing Exh. ES-RDP-1, at 93-94; Companies Reply Brief at 23). Eversource maintains that it applied a minimum size cost allocation method, where the cost of service associated with only minimum size equipment of the distribution system was allocated to each rate class (Companies Brief at 56-57). Further, Eversource states that its electric distribution system is built to meet non-coincident peak so its TOU peak period is appropriate; to use a short peak period would create an opportunity to certain sophisticated customers to shift their load to an off-peak period, therefore creating an intra-class inequity (Companies Brief at 44-45).

ii. <u>MMRC Does Not Excessively Burden Ratepayers</u>

(A) <u>Intervenors</u>

The Attorney General, Cape Light Compact, and NECEC maintain that the Companies should interpret "does not excessively burden ratepayers" in G.L. c. 164, § 139(j) as not excessively burdening MMRC customers (Attorney General Brief at 18, 20; Cape Light Compact Brief at 12-13; NECEC Reply Brief at 6). The Attorney General maintains that the burden placed on a customer electing to participate in net metering with an MMRC extends beyond a mathematical calculation of the customer's bill (Attorney General Reply Brief at 8). The Attorney General argues that the Department can decide what factors should be considered when determining whether the Companies' MMRC proposal excessively burdens ratepayers (Attorney General Brief at 8-9). Cape Light Compact argues that MMRC customers would be paying more for distribution service than non-net metering customers who reduce their loads through conservation and energy efficiency (Cape Light Compact Brief at 13).

NECEC maintains that considering burdens to all ratepayers will be ensured when applying the rate structure goals to the MMRC, and that the Act in this instance is referring to not burdening MMRC customers (NECEC Reply Brief at 7). Further, NECEC argues that Eversource has not shown that its proposed MMRC does not excessively burden ratepayers because it has not demonstrated that the MMRC will apply charges to customers that are commensurate with the costs to serve those customers or reflect a justified deviation from the charges applied to other customers within the same rate class (NECEC Brief at 29).

Cape Light Compact, Sunrun and EFCA, and NECEC maintain that the MMRC includes other costs that will affect ratepayers. Cape Light Compact argues that Eversource has not presented an estimate of the order of magnitude of the costs for administering the MMRC demand charge that will be passed onto ratepayers (Cape Light Compact Brief at 53). Cape Light Compact argues that such costs include new demand meters, installation fees, customer education, recoding and testing the billing system, training call center representatives, and other costs (Cape Light Compact Brief at 53).

Sunrun and EFCA argue that Eversource's claims that a residential customer who participates in net metering services and pays an MMRC will still see a substantial bill decrease are unsupported by record (Sunrun and EFCA Brief at 8). Sunrun and EFCA maintain that a Rate R-1 customer with a 4-kW system could see its annual bill increase by 34 percent (Sunrun and EFCA Brief at 8, citing Exhs. SREF-TW/MW-1 (Surr.) at 4; DPU-10-19, Att.).

Further, NECEC argues that Eversource's mention of the bill reduction from 79 percent to 71 percent does not indicate whether the difference is justified or excessive (NECEC Reply Brief at 7). According to NECEC, a more reasonable analysis is to examine a customer with a solar generation system on-site and to determine what the bill would be with and without an MMRC (NECEC Reply Brief at 8). In this regard, NECEC asserts that the customer's bill in the previous example would be 36 percent higher with an MMRC (NECEC Reply Brief at 8). Further, NECEC argues that customers exempt from an MMRC should include customers who already have installed distributed generation, low-income customers, and customers in publicly-supported housing (NECEC Brief at 38, citing Exh. SREF-TW/MW-1 (Supp.) at 3, 30).

The Attorney General and Sunrun and EFCA argue that the Department should reject Eversource's MMRC proposal because it does not properly estimate bill impacts and therefore fails to accurately assess if MMRC customers will be excessively burdened (Attorney General Brief at 22; Sunrun and EFCA Brief at 8). The Attorney General and Sunrun and EFCA maintain that a demand charge based on the highest 15-minute measurement in a month will be higher than an hourly average (Attorney General Brief at 21, citing Tr. 16, at 3256; Sunrun and EFCA Brief at 8-9; Sunrun and EFCA Reply Brief at 9). The Attorney General maintains that, because the Companies calculated bill impacts of the MMRC based on hourly data, the Companies have underestimated the demand charge that MMRC customers will likely have to pay (Attorney General Brief at 21). Sunrun and EFCA argue that the Companies failed to model the impacts of the MMRC on residential customers with a higher or lower usage pattern than the "average" customer (Sunrun and EFCA Brief at 9). Furthermore, Sunrun and EFCA maintain that Eversource did not model the impact of an MMRC on large users with differently sized systems (Sunrun and EFCA Brief at 9). Finally, Sunrun and EFCA contend that Eversource did not perform a sensitivity analysis that varies residential customers' load assumptions despite the Department's stating that an MMRC should reflect consideration of "bill impact analys[es], including sensitivities, for various types of customers, not just residential customers" (Sunrun and EFCA Brief at 10, citing Net Metering Rulemaking, D.P.U. 16-64-E at 20 (January 13, 2017); Sunrun and EFCA Reply Brief at 11). Contrary to Eversource's claim that it provides bill impacts analyzing multiple customer scenarios, Sunrun and EFCA argue that Exhibit SREF-1-42 does not constitute a sensitivity analysis (Sunrun and EFCA Reply Brief at 10).

(B) Companies

Eversource maintains that the Attorney General, Cape Light Compact, and NECEC incorrectly interpret who the MMRC should not unreasonably burden (Companies Brief at 54; Companies Reply Brief at 18). The Companies maintain that the Department should review the MMRC through the prism of whether the rate would excessively burden all customers based on a plain reading of the statute and the broader context of the Act (Companies Brief at 55; Companies Reply Brief at 19).

Eversource also contends that the MMRC does not burden net metering customers as illustrated by an average residential customer, who sizes a solar array to its demand, will see a bill reduction of 71 percent with the application of the MMRC rather than 79 percent without an MMRC (Companies Brief at 56; Companies Reply Brief at 23). Further, Eversource argues that the Attorney General does not demonstrate that the eight-percent difference is "excessively burdensome" to all ratepayers (Companies Reply Brief at 19). Regarding NECEC's argument that a customer's bill will be 36 percent higher with the

MMRC than without the MMRC, the Companies argue that customers and solar developers can factor in the increase into their contracts, given that customer bills prior to the installation of solar would have been approximately $1,500 per year, the cost of solar has declined since the introduction of net metering, and DOER is introducing new incentives to solar developers under the Solar Massachusetts Renewable Target program (Companies Reply Brief at 39). Finally, Eversource argues that the Companies provided numerous iterations of bill impacts to both residential and commercial customers under a variety of scenarios, which overall demonstrates that MMRC customers will still experience savings (Companies Brief at 53, citing Exhs. SREF-1-42; VS-4-1; DPU-10-20; DPU-1-21; DPU-10-22; ES-RDP-6, Sch. RDP-4).

iii. MMRC Does Not Unreasonably Inhibit the Development of Net Metering Facilities

(A) Intervenors

Cape Light Compact, NECEC, and Vote Solar assert that Eversource did not conduct a specific analysis that demonstrates that the MMRC would not unreasonably inhibit the development of Class I, Class II, and Class III net metering facilities (Cape Light Compact Brief at 54; NECEC Brief at 29; Vote Solar Brief at 16). Further, DOER recommends that the Department consider carefully the arguments and issues put forward by other intervenors regarding the impact that the Companies' proposal will have on the future development of Class I, Class II, and Class III net metering facilities (DOER Brief at 9).

Some intervenors argue that the MMRC would inhibit the development of these facilities (Cambridge Brief at 12; Barnstable Brief at 10). For instance, Cambridge maintains that the MMRC would: (1) reduce the value of net metering credits, particularly for residential customers; and (2) impose on residential customers a new demand charge, amounting to a penalty on customers that install net metering facilities because they could not predict or control that charge (Cambridge Brief at 12).

Other intervenors maintain that it is possible or likely that an MMRC will inhibit the development of net metering facilities (Barnstable at 12; Cape Light Compact Brief at 54; NECEC Brief at 30; Sunrun and EFCA Brief at 10). For instance, Barnstable argues that it is unlikely that CVEC and Weston would support future clean energy projects due to the uncertainty of the benefits (Barnstable Brief at 10, citing CVEC-JR-1, at 3; CVEC-CAW-2, at 4; Tr. 19, at 3714-3715). Cape Light Compact argues that the uncertainty whether a customer will be better or worse off with or without net metering is likely to deter some customers from installing distributed generation (Cape Light Compact Brief at 54, citing Tr. 16, at 3341-3342). NECEC argues that Eversource's own analyses show that the MMRC would substantially reduce customer's bill savings from net metering – by $2,500 for a Rate R-1 customer installing a 4 kW system and by $3,800 for a Rate R-1 customer installing a 6-kW system – potentially dissuading customers from investing in solar (NECEC Brief at 30, citing Exh. SREF-TW/MW-1 (Surr.) at 4). Sunrun and EFCA argue that Eversource cannot guarantee that solar development will not be inhibited because Eversource conducted little analysis on the combined impact of the MMRC and DOER's Solar Massachusetts Renewable Target program, which will be the future solar incentive program for customers that install distributed generation (Sunrun and EFCA Brief at 11).

(B) Companies

Eversource argues that the MMRC will not unreasonably inhibit the development of Class I, Class II, or Class III net metering facilities (Companies Brief at 23). The Companies maintain that the impacts: (1) will be well known in advance; and (2) will not be unreasonable relative to the overall net metering credits expected once an MMRC is implemented (Companies Brief at 23-24, 53, citing Exh. SREF-1-42; Companies Reply Brief at 44).

iv. Offset Reasonably and Prudently Incurred Costs

(A) Intervenors

Cape Light Compact argues that the MMRC is not designed to mirror reasonably and prudently incurred capacity costs, as alleged, because Eversource does not build its distribution system to serve the sum of all its customers' individual non-coincident maximum demands (Cape Light Compact Brief at 54-55). Cape Light Compact also argues that the MMRC is not dedicated to offsetting reasonably and prudently incurred costs because it was designed such that Eversource is likely to over collect its revenue target at the direct expense of new net metering customers (Cape Light Compact Brief at 55).

(B) Companies

The Companies did not address this issue on brief. In its initial filing, Eversource asserted that a demand charge quantifies and provides a signal to customers about the capacity requirements needed to provide service to them through their actual metered demand on the electric distribution system each billing period (Exh. ES-RDP-1, at 95).

b. Alternative MMRC Structures

i. Intervenors

DOER argues that the MMRC is inconsistent with the Act, because the structure of Eversource's proposal is not a true minimum charge (DOER Brief at 8). DOER contends that a minimum bill that requires net metering customers to pay a customer charge each billing period, regardless of whether they have a net metering credit balance, could be an example of an appropriate alternative structure that addresses this issue (DOER Brief at 9). NECEC and Sunrun and EFCA argue that, if the Department finds that considering some form of an MMRC is warranted, it should direct Eversource to prepare a proposal that adopts an approach similar to that of the nature presented in the Department's straw proposal in docket D.P.U. 16-64,[39] which consisted of a minimum bill set equal to the customer charge (NECEC Brief at 38, Sunrun and EFCA Brief at 17; Sunrun and EFCA Reply Brief at 4, 14). NECEC maintains that such an approach would: (1) be simpler than the Companies' proposal; (2) avoid many of the inefficient price signals; (3) avoid severe bill impacts; (4) avoid departures from the Department's rate structure goals; and (5) with appropriate support from Eversource, would be able to satisfy statutory and regulatory requirements (NECEC Brief at 38-39). Sunrun and EFCA argue that the D.P.U. 16-64

39 The Department staff's straw proposal was presented in a hearing officer memorandum and discussed at a technical conference on August 23, 2016. Net Metering Rulemaking, D.P.U. 16-64, Hearing Officer Memorandum at 3-5 (August 19, 2016). Eversource and the intervenors commenting on this issue participated in that technical conference, namely Acadia Center, the Attorney General, Cambridge, DOER, NECEC, and Sunrun and EFCA, along with other interested stakeholders.

alternative would mitigate the alleged impacts of net metering customers zeroing out their customer-related fixed costs (Sunrun and EFCA Brief at 17).

The Attorney General maintains that a minimum bill tied to the customer charge may result in Eversource's collection of additional funds, but it will not result in behavioral changes in the net metering market to achieve necessary individual and system benefits (Attorney General Brief at 10). The Attorney General recommends that, if the Department contemplates a potential MMRC alternative, it should take into account how class or system average peaks can be utilized to drive individual demand in a way to maximize benefits from the MMRC customer and to the system as a whole (Attorney General Brief at 10).

Sunrun and EFCA argue that the Act does not specify that the fixed costs of the electric distribution system not caused by volumetric consumption must reflect system demand costs (Sunrun and EFCA Reply Brief at 14). Further, Sunrun and EFCA contend that the monthly guarantee that the Companies would collect at least the customer charge should go a long way towards filling any gap between the time Eversource experiences displaced revenues and when it is made whole through the NMRS (Sunrun and EFCA Reply Brief at 14).

Acadia Center asserts that a minimum bill proposal does not satisfy most of the relevant criteria for an MMRC (Acadia Reply Brief at 4). Acadia Center argues that a minimum bill set at the level of the customer charge would not include the vast majority of costs related to the reliability, proper maintenance, and safety of the electric distribution system (Acadia Reply Brief at 5). Acadia Center also contends that minimum bills violate the key rate design criteria of efficiency and fair cost allocation (Acadia Reply Brief at 5).

UMass argues that the Department should not approve the Companies' MMRC but rather should initiate a collaborative proceeding to determine whether and what contribution customers exporting power onto the distribution system should make toward the costs of maintaining the distribution system (UMass Brief at 15). Acadia Center also urges the Department to open a generic docket in 2018 to determine a method for analyzing the distinction between avoidable and unavoidable distribution costs, and the process to implement a mechanism that would achieve the goal of equitably collecting these costs (Acadia Center Brief at 21-22; Acadia Center Reply Brief at 5).

ii. Companies

The Companies did not take a position on alternative MMRC structures in this proceeding.

c. Rate Structure Goals

i. Demand Charges and Customer Education

(A) Intervenors

Several intervenors argue that setting an MMRC based on a customer's maximum monthly demand regardless of when the distribution system is peaking is not an appropriate indicator of a customer's contribution to system costs and is not indicative of cost causation, because each customer's non-coincident peak fails to track the peak demand that drives system costs (Attorney General Brief at 22; Acadia Center Brief at 14, 16, 18-19; NECEC

Brief at 32; Sunrun and EFCA Brief at 15; Vote Solar Brief at 9-10; Vote Solar Reply Brief at 7). Cambridge and NECEC maintain that the MMRC does not meet the rate design goal of efficiency (Cambridge Brief at 12; NECEC Brief at 34).

Furthermore, the Attorney General, NECEC, and Vote Solar maintain that designing a demand charge based on non-coincident peak weakens the price signals that encourage a customer to reduce usage during the Companies' peak demand (Attorney General Brief at 22; NECEC Brief at 32; Vote Solar Reply Brief at 7). NECEC maintains that customers whose demand peaks outside of system peak periods would pay too much, and customers whose individual peaks coincide with system peaks may pay too little (NECEC Brief at 32). Cape Light Compact argues that using a 15-minute monthly maximum demand charge for the MMRC seems to be largely due to various limitations on the Companies' billing and information systems and is inappropriate (Cape Light Compact Brief at 44).

Several intervenors argue that the Department should reject the MMRC because Eversource has not established that a demand charge is understandable by customers, especially residential customers (Acadia Center Brief at 14-15; Cape Light Compact Brief at 60; Cambridge Brief at 11; NECEC Brief at 33-34; Sunrun and EFCA Brief at 14; Vote Solar Brief at 11; Vote Solar Reply Brief at 5). Intervenors supporting this position contend that the Companies did not conduct any studies or surveys of their customers to determine whether they could understand the MMRC (Acadia Center Brief at 15; Sunrun and EFCA Brief at 14; Vote Solar Brief at 11). NECEC asserts that the record shows that demand charges will be difficult for residential customers to understand and have been roundly rejected by public utility commissions across the country for that reason (NECEC Brief at 33).

Cape Light Compact argues that splitting the MMRC into three components - a higher fixed customer charge, a demand charge, and a volumetric charge - is unnecessarily complicated (Cape Light Compact Brief at 62). Cape Light Compact and Cambridge argue that the MMRC does not meet the rate design goal of simplicity (Cape Light Compact Brief at 60; Cambridge Brief at 11). Sunrun and EFCA contend that the Companies cited to decades old and biased studies in support of their belief that customers who install distributed generation would know how much their net metering facility generates and know their monthly usage (Sunrun and EFCA Brief at 14).

Several intervenors further argue that imposing a demand charge on residential customers without providing a way for customers to track their electricity consumption and demand, such as through smart meters or in-home displays showing their metered demand, will be problematic because these customers will not be able to alter their behavior (Attorney General Brief at 23; Acadia Center Brief at 15; Acadia Center Reply Brief at 4; Cape Light Compact at 52, 59, 62; Cape Light Compact Reply Brief at 13; Cambridge Brief at 12; DOER Brief at 10; NECEC Brief at 34-35; Sunrun and EFCA Brief at 14; Sunrun and EFCA Reply Brief at 12; Vote Solar Brief at 11, 13). Cape Light Compact and NECEC argue that even if customers tried to control their demand, they would be punished for a single lapse in control of their load during a month (Cape Light Compact Brief at 53, 59; NECEC Brief at 35). Further, Cape Light Compact and Sunrun and EFCA argue that

Eversource concedes that customers either will find it difficult to determine or have no idea when their water heaters cycle on and will not know which appliances give rise to monthly maximum demands (Cape Light Compact Brief at 52, citing Tr. 16, at 3355; Sunrun and EFCA Brief at 15, citing Tr. 16, at 3354-3355; Sunrun and EFCA Reply Brief at 12).

Acadia Center, Cape Light Compact, DOER, Sunrun and EFCA, and Vote Solar argue that the Department should reject the MMRC because Eversource has not developed a detailed customer outreach and education plan (Acadia Center Brief at 15; Cape Light Compact Brief at 63-64; Cape Light Compact Reply Brief at 17; DOER Brief at 10-11; Sunrun and EFCA Brief at 14; Sunrun and EFCA Reply Brief at 12; Vote Solar Brief at 11-12; Vote Solar Reply Brief at 5). Cape Light Compact argues that Eversource's failure not file a customer education plan misses the requirement to present adequate strategies to ensure that residential customers will understand the MMRC (Cape Light Compact Reply Brief at 17).

(B) Companies

The Companies argue that producing rates based on local coincident peaks is not practical and would yield a more complex set of rates that would be challenging for customers to decipher or respond to appropriately (Companies Reply Brief at 43). Further, the Companies contend that their proposed MMRC balances several different principles and that no rate design can be perfectly efficient and cost based while remaining simple and producing gradual bill impacts (Companies Reply Brief at 44). The Companies also maintain that no intervenor has demonstrated that energy charges are a better measure of cost drivers for all components of the distribution system (Companies Reply Brief at 52).

Eversource also contends that it will develop a thorough and comprehensive communications and outreach plan (Companies Reply Brief at 25). Further, Eversource argues that the Companies have substantial experience with small C&I customers that have demand rates (Companies Reply Brief at 30). According to Eversource, small C&I customers should be able to understand their electric bills and make reasoned energy decisions because these customers are already familiar with demand charges (Companies Reply Brief at 30, 51). Moreover, Eversource argues that the intervenors have not provided evidence that customers are incapable of managing their electric usage nor cannot dedicate time to monitor their demand levels (Companies Reply Brief at 30).

Eversource acknowledges the critical need to educate customers on the implementation of the MMRC and argues that, prior to its rate case filing in January 2017, the Companies developed a thorough and comprehensive communications and outreach plan (Companies Reply Brief at 25). Eversource avers that it has committed to further developing its communications to customers prior to January 1, 2019, but cannot complete such a plan without knowledge of the specifics of the Department's ultimate decision on this matter (Companies Reply Brief at 25, 43).

ii. Two Different Charges in One Rate Class

(A) Intervenors

Acadia Center and NECEC argue that the Act does not authorize the creation of separate rate structures and that the Department cannot arbitrarily assign a Rate R-1 customer to another set of per-kWh rates, even through application of the MMRC (Acadia Center Brief at 19; NECEC Brief at 37). The Attorney General and NECEC maintain that it is unfair for MMRC customers and non-MMRC customers to receive service under the same rate class yet face different customer charges using the same cost of service study (Attorney General Brief at 23; NECEC Brief at 36; NECEC Reply Brief at 11). In particular, the Attorney General argues that charging two different customer charges based within the same rate class provides one group of ratepayers with more control over their electricity bill than the other (Attorney General Brief at 24). Further, the Attorney General maintains that an MMRC customer will have less ability than a non-MMRC customer to manage its bill due to a higher fixed charge component (Attorney General Brief at 24). NECEC contends that the Department should not allow any subgroup of customers within a class to be carved out for different rate design treatment based solely on an assertion that those customers should pay more, and without justification that the rate design proposal is based on the cost to serve those customers (NECEC Reply Brief at 12). Cape Light Compact and NECEC argue that imposing divergent charges to some customers within a class and not to others without evidence is unfair and discriminatory (Cape Light Compact Brief at 66; NECEC Brief at 36, 38).

(B) Companies

Eversource argues that it did not separate net metering customers into a separate class because it is not proposing to assign separate costs to these customers (Companies Brief at 58). Eversource claims that the cost to serve these customers has been evaluated through the cost of service study conducted for their respective rate class (Companies Brief at 58). In response to the Attorney General's argument that an MMRC customer will have less ability than a non-MMRC customer to manage its bill due to a higher fixed charge component, the Companies argue that this statement is illogical since an MMRC customer has installed on-site generation with the intention of significantly reducing its billed charges from the distribution company (Companies Brief at 59). The Companies contend that different rate designs within a rate class are not new and are not discriminatory so long as they are designed to be revenue neutral to the otherwise applicable rate (Companies Reply Brief at 40).

d. Additional Issues

i. Subjecting Class I Net Metering Facilities to an MMRC

Sunrun and EFCA question whether the Department has authority to subject Class I net metering facilities to an MMRC (Sunrun and EFCA Brief at 17; Sunrun and EFCA Reply Brief at 15). Sunrun and EFCA argue that it is unclear whether G.L. c. 164, § 139(j), which describes the MMRC, repeals or alters G.L. c. 164, § 139(d), which prohibits imposition of special fees on Class I net metering facilities (Sunrun and EFCA Brief at 17; Sunrun and EFCA Reply Brief at 15). Sunrun and EFCA argue that it is incumbent upon the Legislature to fix this uncertainty (Sunrun and EFCA Brief at 17; Sunrun and EFCA Reply Brief at 15). No other party addressed this issue.

ii. Impacts to Energy Efficiency

(A) Intervenors

Cape Light Compact argues that Eversource failed to present evidence of the impact of the MMRC on the Commonwealth's energy efficiency programs (Cape Light Compact Brief at 55). Further, Cape Light Compact contends that Eversource's MMRC violates the core rate design principal of efficiency because the demand charge, the higher fixed customer charge, and the reduced volumetric charge weaken signals to consumers to decrease energy consumption and to participate in energy efficiency programs (Cape Light Compact Brief at 58). Cape Light Compact also claims that ratepayers will be excessively burdened because of the improper price signals for energy efficiency, which will cause over-investment in electric distribution system capacity (Cape Light Compact Reply Brief at 13).

In response to Eversource's argument that price signals will be muted, NECEC maintains that even customers that net meter and carry forward net metering credits respond to price signals (NECEC Reply Brief at 9). Further, NECEC and Vote Solar argue that customers that net meter can still benefit from reducing usage or installing energy efficiency measures (NECEC Reply Brief at 9; Vote Solar Reply Brief at 6). Sunrun and EFCA and Vote Solar argue that Eversource has not provided evidence to support its claim that net metering customers do not respond to price signals (Sunrun and EFCA Reply Brief at 13; Vote Solar Reply Brief at 6).

(B) Companies

Regarding concerns related to the MMRC impact on energy efficiency, the Companies argue that the MMRC is not a customer charge but rather a demand charge tied to customer usage (Companies Reply Brief at 43). The Companies contend that proposals affecting demand are consistent with energy efficiency (Companies Reply Brief at 43). Furthermore, Eversource argues that any rate design predicated on per-kWh charges will have muted price signals under net metering, because a net metering customer can eliminate all of those charges and thereby remove any price signal regarding its use of the distribution system (Companies Brief at 57; Company Reply Brief at 39-40, 43). Eversource avers that this price signal is further distorted by the ability of net metering customers to carry credits forward from one billing period to the next (Companies Brief at 57). Eversource responds that, despite the characterization offered by the intervenors, it does not argue that price signals are irrelevant to customers who install distributed generation (Companies Reply Brief at 39).

iii. Small and Medium Commercial Customers with Demand Charges

TEC argues that small and medium commercial customers that have a demand charge should not be subject to an MMRC charge, because it is redundant (TEC Brief at 23). TEC argues that the demand charge alone should be a sufficient mechanism for the Companies to recover distribution charges from small and medium customers who install net metering facilities (TEC Brief at 23). TEC is not opposed to an increase in the fixed charges for customers to cover the costs of administration for net metering, but argues that the MMRC, in combination with a demand charge, is unwarranted (TEC Brief at 23).

4. Analysis and Findings

a. Standard of Review

An MMRC proposal must meet several procedural requirements. MMRC proposals shall be filed with the Department in: (i) the distribution company's base distribution rate proceeding; or (ii) a revenue neutral rate design filing that is supported by appropriate cost of service data across all rate classes. G.L. c. 164, § 139(j). Further, the Department "may only approve a proposal for a monthly minimum reliability contribution after the aggregate nameplate capacity of installed solar generating facilities in the [C]ommonwealth is equal to or greater than 1,600 megawatts." G.L. c. 164, § 139(j). Any MMRC approved by the Department must take effect no later than December 31, 2018. G.L. c. 164, § 139(j).

An MMRC proposal must meet several substantive requirements. The Department may approve an MMRC that: (1) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (2) does not excessively burden ratepayers; (3) does not unreasonably inhibit the development of Class I, Class II, and Class III net metering facilities; and (4) is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system. G.L. c. 164, § 139(j). Further, the Department may exempt or modify an MMRC for low-income ratepayers and, for any period through 2020, any class or sub-class of Class I, Class II, or Class III net metering facilities that were in service by

December 31, 2016. G.L. c. 164, § 139(j). The Department also may approve changes to the MMRC for individual electric distribution companies in any future base rate proceeding. G.L. c. 164, § 139(j).

Further, an MMRC must be just and reasonable. The Department is charged with ensuring that any rates are just and reasonable. Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 264 n.13 (2002); Attorney General v. Department of Public Utilities, 392 Mass. 262, 265 (1984); Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 371 Mass. 881, 882 (1977); New England Gas Company, D.P.U. 10-114, at 22 (2011); Boston Gas Company, D.P.U. 93-60, at 212 (1993). A utility's rates are just and reasonable when its rates afford it the opportunity to meet its cost of service, including a fair and reasonable return on honestly and prudently invested capital. See Boston Gas Co. v. Department of Pub. Utilities, 367 Mass. 92, 97 (1975); Lowell Gas Co. v. Department of Pub. Utilities, 324 Mass. 80, 94, cert. denied, 338 U.S. 825 (1949); Donham v. Public Service Commissioners, 232 Mass. 309, 326 (1919). Finally, as set forth in Section IV.A above, the Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 15-155, at 383; D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341.

b. D.P.U. 16-64-E

The Department has directed each electric distribution company to consider the following types of data to permit the public to better evaluate an MMRC proposal: (1) an analysis of the impact of market net metering credits on the need for an MMRC; (2) a bill impact analysis, including sensitivities, for various types of customers, not just residential customers; (3) cost of service studies supporting the allocation between fixed and variable charges; and (4) an analysis justifying the need for an MMRC. Net Metering Rulemaking, D.P.U. 16-64-E at 21-22 (January 13, 2017). The Department further encouraged each distribution company to continue discussing MMRC proposals and data requests with interested stakeholders in advance of an adjudicatory proceeding involving an MMRC. D.P.U. 16-64-E at 22.

Consistent with the directives in D.P.U. 16-64-E, the Department finds that the Companies provided evidence demonstrating sufficient bill impact analyses (Exh. DPU-10-19, Att.). The Department further finds that the Companies' cost of service studies support the allocation between fixed and variable charges (Exhs. DPU-1-8, Att. at 55-56; AG-48-6; RR-DPU-49). The Department concludes that the Companies considered an analysis of the impact of market net metering credits, bill impact sensitivities, and the need for an MMRC.

The Department managed a process in docket D.P.U. 16-64 to consider alternative MMRC proposal methods in a non-adjudicatory proceeding. The Department held two technical conferences on August 23, 2016 and October 24, 2016, to discuss Department staff's straw proposal and alternative MMRC proposals. The Department subsequently sought written comments. D.P.U. 16-64-E at 2. Throughout docket D.P.U. 16-64 and this proceeding, no entity aside from the electric distribution companies presented a feasible alternative MMRC proposal with supporting evidence. At the conclusion of the process in docket D.P.U. 16-64, the Department determined that opening a generic MMRC proceeding to investigate a model MMRC or alternative MMRC structures was unnecessary. D.P.U. 16-64-E at 22. Here, the Department reaffirms that such a proceeding is unnecessary.

c. Procedural Requirements

The Act was signed on April 11, 2016, nine months prior to Eversource's filing in the instant proceeding. In compliance with G.L. c. 164, § 139(j), on January 17, 2017, Eversource filed its MMRC proposal in the Companies' base distribution rate proceeding. On September 8, 2017, the Department established the MMRC Date as May 1, 2017, and certified that as of that date there were 1,655.96 megawatts direct current interconnected to the electric distribution system. D.P.U. 16-64-G at 19-20.

The Companies propose to apply the MMRC to new residential and C&I net metering customers with an in-service date on or after January 1, 2019 (Exhs. ES-RDP-1, at 91; Exh. DPU-56-9, at 8 (Supp.)). The Companies submit that approving an MMRC results in an effective date, one that may precede the date on which the MMRC is charged to customers (Exhs. ES-RDP-1, at 91; DPU-46-4, at 1). Therefore, Eversource states that the MMRC charge can be effective during the statutory time period before it is actually applied to any customer bills (Exh. DPU-46-4, at 1-2). The Department disagrees with Eversource's statutory interpretation. Rather, the Department finds that the Companies proposed date to apply the MMRC to new net metering host customers of January 1, 2019, is inconsistent with G.L. c. 164, § 139(j) because January 1, 2019 is after the effective date of December 31, 2018 set by statute.

When the statute's language is certain, we afford its ordinary meaning. ENGIE Gas & LNG LLC v. Department of Pub. Utilities, 475 Mass. 191, 197 (2016). The language of the statute is "the primary source of insight into the intent of a legislature." Commissioner of Correction v. Superior Court Dept. of Trial Court For the County of Worcester, 446 Mass. 123, 124 (2006), citing International Fidelity Insurance Company v. Wilson, 387 Mass. 841, 853, (1983). The Act clearly states that an MMRC shall be effective not later than December 31, 2018. G.L. c. 164, § 139(j). If the Department approves an MMRC on a date before December 31, 2018, and an MMRC is not applied to any customer accounts in that time frame, the Order date cannot serve as the MMRC effective date. The Department finds that to comply with the Act, an MMRC must be applied to at least one rate class' customer accounts by December 31, 2018. Therefore, the Department concludes that Eversource has met two of the three procedural requirements for its MMRC proposal in that was properly filed in a base rate proceeding and it is pending after the MMRC Date of May 1, 2017, but Eversource fails to meet the third requirement of being effective no later than December 31, 2018.

The Department determines that while the Companies met multiple procedural requirements, Eversource has not met the procedural requirement that an MMRC is effective not later than December 31, 2018, because the Companies' MMRC proposal is slated to be applied in the first instance after that date on January 1, 2019. The Department concludes that an MMRC must have an effective date of December 31, 2018, which means that the MMRC should be included on net metering host customer bills with net metering facilities that are interconnected on and after December 31, 2018.

d. Substantive Requirements

i. Statutory Requirements

The Act includes multiple substantive requirements for the Department to consider in reviewing an MMRC proposal. As a threshold matter, the Act requires that "[a]ny such minimum contributions shall ensure that all distribution company customers contribute to the fixed costs of ensuring the reliability, proper maintenance and safety of the electric distribution system." G.L. c. 164, § 139(j). Below, the Department analyzes the substantive statutory requirements.

(A) Equitable Allocation

The Act states that the Department "may approve [...an MMRC] that: (i) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption" and three other criteria discussed below. G.L. c. 164, § 139(j). Intervenors raise issues about the cost shift of net metering, benefits of distributed generation, and cost allocation with regard to quantifying and equitably allocating fixed costs. The Act does not detail what constitutes equitable allocation of fixed costs.

(1) Cost Shift of Net Metering

The Act does not require a proven cost shift as a prerequisite to approve an MMRC. Eversource calculates that its DDR was approximately $8,500,000 in 2016, which was collected through the annual NMRS that is charged to all ratepayers (Exhs. DPU-10-12; DPU-46-9 (Distribution Revenue Tab); SREF-1-28). In 2016, Eversource paid its customers $67,492,869 in net metering credits (Exh. SREF-1-28, at 2(a)).

The Companies' current net metering tariffs allow Eversource to recover from all customers an annual surcharge through the NMRS, or other applicable reconciling mechanism, for: (1) costs of credits paid to net metering customers; (2) DDR; and (3) prior period reconciliation adjustments. M.D.P.U. No. 163D, § 1.08(4); M.D.P.U. No. 1048G, § 1.08(4). Of these three components, the costs of credits paid to net metering customers are based on net metering customers' amount of energy generated. The DDR is the non-reconciling distribution portion of revenue that would have been collected by the Companies in the relevant year, but was displaced by the generation used by net metering customers. M.D.P.U. No. 163D, § 1.08(4); M.D.P.U. No. 1048G, § 1.08(4). When filing its NMRS, NSTAR Electric calculates the DDR by subtracting net metered volumetric consumption from its estimate of total customer-owned generation output and multiplying it by the applicable non-reconciling distribution rate. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-174, at 3 (2016).

The Companies' MMRC proposal is designed to recover the cost of service from customers who have reduced their kWh usage relative to the test year billing determinants through net metering (Exh. DPU-46-12). Nonetheless, the Department concedes that customers taking net metering services directly receive the economic benefits of the net metering system. NSTAR Electric Company, D.P.U. 15-174, at 32 (2016). The costs of net metering, however, are borne by all electric customers, whether or not they receive net metering credits. D.P.U. 15-174, at 32. Consequently, there is a transfer of costs rooted in the net metering system (Exh. DPU-10-13). D.P.U. 16-157, at 9, 16. The Department concludes that the Companies have demonstrated a cost shift from net metering to non-net metering customers by identifying costs directly imposed by net metering facilities on the distribution system (Exhs. ES-RDP-1, at 95-96; ES-RDP-Rebuttal-1, at 20; DPU-46-9, Att.).

(2) Benefits of Net Metering

The Act does not require a determination regarding the possible benefits of net metering facilities as a prerequisite to approve an MMRC. Several intervenors argue that there are benefits of distributed generation that should be considered (Acadia Center Brief at 17; Cape Light Compact Brief at 47-48; Cambridge Brief at 11; NECEC Brief at 26; NECEC Reply Brief at 6; Sunrun and EFCA Brief at 6; Sunrun and EFCA Reply Brief at 6; Vote Solar Brief at 5, 7, citing D.P.U. 15-155, at 458; Vote Solar Reply Brief at 4).

The Department has previously stated that net metering is an important tool in the advancement of renewable energy. Solect Energy Development LLC, D.P.U. 16-21, at 12 (2016); BCC Solar Energy Advantage, Inc., D.P.U. 14-149, at 18 (2015); Borrego Solar Systems, Inc., D.P.U. 12-80, at 7 (2012). Further, the Department has stated that there is a public interest in the advancement of renewable energy projects in the Commonwealth.

D.P.U. 16-157, at 18-19; D.P.U. 15-174, at 31-32; Solect Energy Development LLC, D.P.U. 16-21, at 12 (2016); BCC Solar Advantage, Inc., D.P.U. 14-149, at 18; D.P.U. 12-80, at 7. While there are benefits resulting from net metering installations, the Department finds that the Act does not require a determination of the allocation of benefits (e.g., whether such facilities result in benefits to individual facilities, virtual net metering customers, the electric distribution system, or over the long-run).

(3) Equitable Allocation of Costs

Eversource states that it isolated demand-related costs of the electric distribution system, which are fixed (Exh. ES-RDP-1, at 86). Eversource asserts that its MMRC proposal derives a minimum distribution system cost of providing service, based on the embedded cost of service studies, which includes the following components of the electric distribution system: poles, conduit, overhead and underground conductors, and service transformers (Exhs. ES-RDP-1, at 86, 94; DPU-10-6, at 1). Further, the MMRC proposal is designed based on each individual customer's actual use of the distribution system because the Companies separated customer costs from demand costs and developed a unit demand rate allowing the MMRC charge for each customer in a given billing cycle to be based on a customer's actual metered demand (Exh. DPU-10-6, at 2). By contrast, Cape Light Compact argues that the proposed MMRC demand charge fails to equitably allocate costs because Eversource proposes to allocate the costs based on each rate class' contribution to peak demand, but does not perform a separate cost allocation study for net metering customers within that rate class (Cape Light Compact Brief at 52).

The MMRC must be supported by cost of service data. G.L. c. 164, § 139(j). The Department finds that the Companies' proposal for a demand charge based on a minimum distribution system cost of providing service allocated to each rate class is based upon documented fixed costs (RR-DPU-50, Att. (i) at Exh. ES-RDP-6 (ALT1), Schs. RDP-3, RDP-4). The Department concludes that Eversource's MMRC proposal is supported by an accurate representation of customer utilization of the electric distribution system because it is based on a customer's non-coincident peak demand, which is consistent with how the Companies undertake electric distribution system planning and is reflected through the allocation of distribution costs on non-coincident peak (Exhs. ES-RDP-1, at 14-15; ES-ACOS-1, at 5, 8-10; DPU-1-3; DPU-60-3). D.P.U. 10-70, at 294-296. The Department further finds that Eversource's MMRC proposal is supported by appropriate cost of service data, in compliance with G.L. c. 164, § 139(j), because the demand charges are derived using costs identified as reliability in the ACOSS (Exhs. DPU-1-8, Att. at 55-56; AG-1-1; AG-48-6; RR-DPU-50, Att. (i) at Exh. ES-RDP-6 (ALT1), Sch. RDP-2).

(4) Equitable Allocation of Fixed Costs Conclusion

Based on the above findings, the Department concludes that Eversource has provided sufficient evidence to demonstrate that the MMRC proposal equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption in compliance with G.L. c. 164, § 139(j).

(B) MMRC Does Not Excessively Burden Ratepayers

The Department may approve an MMRC that "does not excessively burden ratepayers" and satisfies three other criteria. G.L. c. 164, § 139(j). As discussed above, intervenors raise issues about the entities that should not be burdened. The Act does not define "excessively burden".

Eversource argues that the prism through which the Department should consider whether the MMRC would excessively burden customers is all customers (Companies Brief at 55). Further, the Companies assert that MMRC customers still benefit because their bills will be lower than if they did not have net metering, the cost of distributed generation, particularly solar, has declined since the introduction of net metering, and there are forthcoming incentives available through DOER (Companies Reply Brief at 39). By contrast, multiple intervenors maintain that the Department should consider only whether MMRC customers would be excessively burdened (Attorney General Brief at 18, 20; Cape Light Compact Brief at 12-13; NECEC Reply Brief at 6).

Where there is a statutory gap, the agency charged with the administration of a statute is to spell out details of the legislative policy. United States v. Mead Corporation, 533 U.S. 218, 227 (2001), citing Chevron U.S.A., Inc. v. Natural Resources Defense Council, 467 U.S. 837, 843-844 (1984); Middleborough v. Housing Appeals Committee, 449 Mass. 514, 523 (2007), citing Zoning Board of Appeals of Wellesley v. Housing Appeals Committee, 385 Mass. 651, 654 (1982).

The MMRC statute states that "[a]ny such minimum contributions shall ensure that all distribution company customers contribute to the fixed costs of ensuring the reliability, proper maintenance and safety of the electric distribution system." G.L. c. 164, § 139(j) (emphasis added). Just two sentences later, the statute declares than an MMRC may be approved that "does not excessively burden ratepayers." G.L. c. 164, § 139(j). The Department does not have the legislative authority to add or remove rate components to the statute. See Dartt v. Browning-Ferris Industries, Inc. (Mass.), 427 Mass. 1, 8-9 (1998), citing Bronstein v. Prudential Insurance Company, 390 Mass. 701, 706 (1984) (court will not add to a statute a word that the Legislature had the option to, but chose not to, include). However, because the statute does not include qualifying language between the term "burden" and "ratepayers," the Department finds that it must consider whether the MMRC would excessively burden all ratepayers. Further, the Department has an obligation to consider all ratepayers in its rate design decisions. G.L. c. 164, §§ 1A, 1F, 94I.

In viewing whether the MMRC proposal excessively burdens all ratepayers, the Department considers the proposed bill impacts associated with the MMRC proposal. The impact of the Companies' MMRC charge, if approved as proposed, would reduce the value of net metering credits for host customers subject to the MMRC (Exhs. DPU-10-19, Att.; DPU-10-20, Att.; DPU-10-21, Att.; DPU-10-22, Att.; VS-4-1; RR-DPU-50, Att. (i) at Exh. ES-RDP-6 (ALT1)). Since the Department has determined that a cost shift exists between net metered and non-net metered customers, implementation of an MMRC reduces the effects of the cost shift and, as such, does not burden all ratepayers. Further, the

Department finds that an MMRC benefits non-net metered customers by reducing the NMRS, which is charged to all customers.

The Department now considers whether an MMRC creates an excessive burden to customers that would be subject to the MMRC. Excessive is defined as "exceeding what is proper, necessary, or normal." Webster's II New College Dictionary 390 (3rd ed. 2001). The Department notes that host customers taking service under the net metering tariff will continue to receive net metering credits in accordance with G.L. c. 164, §§ 138, 139(b½). The MMRC will not prevent customers from receiving net metering credits, but rather will contribute to the recovery of those costs that are necessary to ensure that all distribution company customers contribute to the fixed costs of ensuring the reliability, proper maintenance and safety of the electric distribution system based on the embedded cost (see Exh. SREF-1-42, Att.). Furthermore, these customers will benefit from net metering through continued bill savings even when subject to an MMRC (Exh. ES-RDP-Rebuttal-1, at 22). The Department finds that the MMRC within the net metering structure, with continued benefits for host customers, would not exceed what is proper, necessary, or normal. As such, the Department determines here that the proposed MMRC will not excessively burden ratepayers with an MMRC or ratepayers without an MMRC in compliance with G.L. c. 164, § 139(j).

(C) MMRC Does Not Inhibit the Development of Net Metering Facilities

The Department may approve an MMRC that "does not unreasonably inhibit the development of Class I, Class II, Class III facilities" and three other criteria. G.L. c. 164, § 139(j). Eversource argues that an MMRC will result in an adjustment to the kWh charge, where applicable, and the net metering credit value for some rate classes, which will be known in advance and are not unreasonable relative to overall net metering credits (Companies Brief at 52-57; Exh. ES-RDP-1, at 95). Multiple intervenors argue that Eversource failed to conduct a specific analysis that demonstrates that the MMRC would not unreasonably inhibit the development of net metering facilities (Cape Light Compact Brief at 54; NECEC Brief at 29; Vote Solar Brief at 16). Other intervenors argue that the MMRC would or would likely unreasonably inhibit the development of net metering facilities (Barnstable Brief at 10; Cambridge Brief at 12; Cape Light Compact Brief at 54; NECEC Brief at 30; Sunrun and EFCA Brief at 10).

As a matter of statutory interpretation, where the language of a statute is "sufficiently ambiguous to support multiple rational interpretations," the court looks to the cause of its enactment, the mischief or imperfection to be remedied and the main object to be accomplished, to the end that the purpose of its framers may be effectuated." Kain v. Department of Environmental Protection, 474 Mass. 278, 286, (2016). In Kain, the Court held that"[a]ll the words of a statute are to be given their ordinary and usual meaning" and we construe "each clause or phrase … with reference to every other clause or phrase without giving undue emphasis to any one group of words, so that, if reasonably possible, all parts shall be construed as consistent with each other so as to form a harmonious enactment effectual to accomplish its manifest purpose." 474 Mass. at 287; see also ENGIE Gas & LNG LLC v. Department of Public Utilities, 475 Mass. 191, 200 (2016). The Act does not provide a roadmap regarding how the Department should interpret "unreasonably inhibit."

"Inhibit" is defined as "to restrict or hold back, restrain." Webster's II New College Dictionary 570 (3rd ed. 2001). Eversource's bill impact analyses show that net metering host customers with an MMRC charge will continue to see savings (Exh. ES-RDP-Rebuttal-1, at 22 (August 22, 2017)). Across all rate classes, the Companies' analyses show that the MMRC will have a minimal effect on the total savings (i.e., the payment/credits customers receive) realized by net metering customers (Exhs. DPU-10-19; DPU-10-20; DPU-10-21; DPU-10-22; NECEC-6-2; NECEC-8-1; NECEC-8-2; NECEC-8-3; NECEC-8-5; NECEC-10-3; SREF-1-42). The Department considered the information provided by multiple municipal intervenors that the MMRC could possibly inhibit the development of net metering facilities, but we find that such information rests on such a degree of speculation as to be unreliable (Exhs. CVEC-JR-1, at 3; CVEC-CAW-2, at 4; SREF-TW/MW-1 (Surr.) at 4; Tr. 19, at 3714-3715).

The Department finds that any likelihood that the MMRC could inhibit the development of future net metering facilities is lessened by the Companies' evidence supporting continued bill savings and net benefits for host customers of net metering facilities with an MMRC charge (Exh. SREF-1-42, Att.). Further, the Department finds that if the volume of future net metering facility development is reduced as a result of an MMRC charge, such diminution would not be unreasonable. Host customers of such net metering facilities have the option to participate in other incentive programs, which will be unaffected by an MMRC (Exh. DPU-46-20).[40] Therefore, it is not reasonable to determine that a decrease in net metering credits would halt investment in Class I, Class II, or Class III net metering facilities when considering other public policies that provide financial incentives for these facilities. As such, the Department finds that the proposed MMRC will not unreasonably inhibit the development of Class I, Class II, or Class III net metering facilities in compliance with G.L. c. 164, § 139(j).

(D) Offset reasonably and prudently incurred costs

Eversource argues that it has isolated demand-related costs of the electric distribution system necessary to maintain the reliability, proper maintenance, and safety of the distribution system, and that the demand charge provides a signal to customers about the capacity requirements needed to provide service to them (Exh. ES-RDP-1, at 93-95). Cape Light Compact argues that because Eversource does not build its electric distribution system to serve the sum of all its customers' individual non-coincident maximum demands, the MMRC is not designed to reflect prudently incurred capacity costs (Cape Light Compact

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40 Other incentive programs that may be available to net metering customers, subject to eligibility requirements, include the current solar carve-out program administered by DOER ("SREC II"), SREC II's successor program, Solar Massachusetts Renewable Target Program, and federal and state tax incentives. (Exhs. Tr. 17, at 3464-3465; Companies Reply Brief at 39). See also: http://www.mass.gov/eea/docs/eea/lbe/ppa-and-nma-guidance.pdf.

Brief at 54-55). The Department accepts the Companies' evidence that the Companies have properly identified costs of the electric distribution system necessary to maintain the reliability, proper maintenance, and safety of the distribution system (see Exh. ES-RDP-1, at 89). The intervenors do not dispute that Eversource incurs such costs. As such, the Department finds that the proposed MMRC will be dedicated to offset reasonably and prudently incurred costs necessary to maintain the reliability, maintenance, and safety of distribution system in compliance with G.L. c. 164, § 139(j).

(E) Subjecting Class I Net Metering Facilities to an MMRC

Sunrun and EFCA argue that it is unclear whether G.L. c. 164, § 139(j) repeals or alters G.L. c. 164, § 139(d), which prohibits fees on Class I net metering facilities (Sunrun and EFCA Brief at 17; Sunrun and EFCA Reply Brief at 15). G.L. c. 164, § 139(d) states that "[d]istribution companies shall be prohibited from imposing special fees on Class I net metering facilities, such as backup charges and demand charges, or additional controls or liability insurance, as long as the facility meets the other requirements of the interconnection tariff and all relevant safety and power quality standards." Wherever possible, statutes should be interpreted as a whole to constitute a consistent and harmonious provision. District Attorney for the Northwestern District v. Eastern Hampshire Division of the District Court Department, 452 Mass. 199, 210 (2008), citing Kargman v. Commissioner of Revenue, 389 Mass. 784, 788 (1983). The Department finds that Section 139(d) prohibiting special fees on Class I net metering facilities and Section 139(j) referencing the MMRC can be interpreted harmoniously because a demand charge, as part of an MMRC charge, is not a "special fee." See 220 CMR 18.03(2).

(F) Statutory Requirements Conclusion

The Department finds that Eversource's MMRC meets the four substantive statutory requirements because it: (1) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (2) does not excessively burden ratepayers; (3) does not unreasonably inhibit the development of Class I, Class II, and Class III net metering facilities; and (4) is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system. G.L. c. 164, § 139(j). Because the Department has no evidence of an alternative MMRC on the record in this proceeding, it cannot compare the Companies' MMRC proposal with an alternative structure.

ii. Just and Reasonable Rates

(A) Rate Structure Goals

Eversource states that its MMRC is based on the minimum system cost of the distribution system, allocated to each class on a diversified demand basis, consistent with methods required by the Department (Exh. ES-RDP-1, at 87). Several intervenors allege that imposing a demand charge on residential customers without providing a way for customers to track their electricity consumption and demand will not result in an appropriate price signal, violating the goal of efficiency (Acadia Center Brief at 15; Acadia Center Reply Brief at 4; Attorney General Brief at 23; Cape Light Compact at 52, 59, 62; Cape Light Compact Reply

Brief at 13; Cambridge Brief at 12; DOER Brief at 10; NECEC Brief at 34-35; Sunrun and EFCA Brief at 14; Sunrun and EFCA Reply Brief at 12; Vote Solar Brief at 11, 13). Intervenors also claim that the MMRC is not understandable to customers, especially residential customers, violating the goal of simplicity (Acadia Center Brief at 14-15; Cape Light Compact Brief at 60; Cambridge Brief at 11; NECEC Brief at 33-34; Sunrun and EFCA Brief at 14; Vote Solar Brief at 11; Vote Solar Reply Brief at 5). The Attorney General and Sunrun and EFCA maintain that a demand charge based on the highest 15-minute measurement in a month will be higher than an hourly average, which likely results in the Companies' underestimation of the demand charge that MMRC customers will pay (Attorney General Brief at 21, citing Tr. 16, at 3256; Sunrun and EFCA Brief at 8-9; Sunrun and EFCA Reply Brief at 9). Several intervenors further argue that setting an MMRC based on a customer's maximum monthly demand regardless of when the distribution system is peaking is not indicative of cost causation because each customer's non-coincident peak may not track peak demand that drives system costs (Acadia Center Brief at 14, 16, 18-19; Attorney General Brief at 22; NECEC Brief at 32; Sunrun and EFCA Brief at 15; Vote Solar Brief at 9-10; Vote Solar Reply Brief at 7).

A demand charge is a charge based on a consumer's peak demand over a specified time period, typically the monthly billing cycle (Exh. DPU-46-16). Since most capital investments on the distribution network are driven by peak demand, the Companies state that demand charges will better align the price that consumers pay with the costs that they are imposing on the system (Exh. DPU-46-16). Consistent with the Department's rate structure goals, a demand charge is intended to accurately convey the cost structure of delivering electricity to consumers so that they can make informed decisions about how much power to consume, and at what time (Exh. DPU-46-16).

The Department acknowledges that the imposition of a demand charge for residential customers is atypical.[41,42] Further, the Department acknowledges that a non-coincident peak demand charge may weaken the price signal that encourages a customer to reduce usage during the Companies' peak demand, but no intervenor demonstrated an alternative method that better measures cost drivers for all components of the electric distribution system. The Companies calculated the MMRC for residential customers based on hourly load-research data, but will bill residential customers based on a 15-minute demand period (Tr. 17, at 3472-3473). The Companies assert that they have the ability to bill residential MMRC customers based on their actual hourly demand (Tr. 17, at 3468, 3471). Therefore, to better align the costs of customers' peak usage, the Department directs the Companies to bill residential customers using their actual hourly demand.

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41 In response to intervenor claims that imposition of an MMRC charge is redundant for small and medium C&I customers, the Department concludes that an MMRC charge is appropriate for Rate G-1 and Rate G-2 customers.

42 The record demonstrates that there are 16 electric distribution companies, eleven investor-owned utilities, some operating in several states that offer a residential demand charge (Exh. DPU-46-14). Of the 16, only two of those demand charges are mandatory (Exh. DPU-46-14). The rates from Black Hills Power in Wyoming and Salt River Project in Arizona are mandatory for new customers with distributed generation, while the rate from Alaska Electric Light and Power is mandatory for large residential customers (Exh. DPU-46-14, Att.).

The Department finds that many residential host customers with net metering facilities are more sophisticated than the average residential customer without net metering facilities or customers receiving net metering credits that are not host customers. Responding to a demand charge does not require that the customers know exactly when their maximum demand will occur (Exh. DPU-46-16, at 1). If customers know to avoid the simultaneous use of electricity-intensive appliances, they could easily reduce their maximum demand without ever knowing when it occurs (Exh. DPU-46-16, at 1-2). Eversource cites to four studies suggesting that customers respond to demand charges and note that a new era of demand charge pilots is underway and results are expected in the next year or two (Exh. DPU-46-16, at 3). Nonetheless, the Department recognizes that the imposition of a residential demand charge is a significant shift from current ratemaking in Massachusetts. Therefore, the Department directs Eversource to submit an informational filing with detailed educational plans, customer outreach, and tools by June 1, 2018, for Department review and approval.

The educational plans and tools must be sufficiently detailed to cover a variety of communication methods, including a plan for communicating with residential and small C&I customers with limited English language abilities. The Department will review the informational filing, including the educational plans, customer outreach plans, and tools, prior to the Companies' implementation of the MMRC. The Department further expects Eversource to work collaboratively with interested stakeholders, including the intervenors who evaluated the MMRC proposal, to respond to concerns about the MMRC proposal needing to be understandable and result in customers tracking their demand.

(B) Two Different Charges in One Rate Class

Eversource argues that different rate designs within a rate class are not new and are not discriminatory so long as they are designed to be revenue neutral to the otherwise applicable rate (Companies Brief at 58). The Attorney General and NECEC maintain that it is unfair for MMRC customers and non-MMRC customers to receive service under the same rate class yet face different customer charges using the same cost of service study (Attorney General Brief at 23; NECEC Brief at 36; NECEC Reply Brief at 11). Acadia Center argues that the Act does not authorize the creation of separate rate structures, even with application of an MMRC (Acadia Center Brief at 19; NECEC Brief at 37).

The Department has found that rate classes should be defined on the basis of differences in cost of service. Boston Gas Company, D.P.U. 88-67, Phase II at 18 (1989); Western Massachusetts Electric Company, D.P.U. 86-280-A at 201 (1987). Rate classes should be defined in a way that minimizes cost differences within the class and maximizes cost differences among classes. Bay State Gas Company, D.P.U. 89-81, at 58 (1989); Colonial Gas Company, D.P.U. 86-27-A at 72 (1988). These differences in cost of service are primarily a function of customer load level and load pattern. Boston Gas Company, D.P.U. 84-236-A at 11 (1986). Here, Eversource has provided evidence that MMRC customers within a rate class have a similar customer load level and load pattern as non-MMRC customers within the same rate class (Exhs. DPU-46-10; LI-1-19; SREF-1-36).

Further, the Department has previously approved multiple distribution rate structures within a single rate class (Exh. DPU-10-3). Boston Electric Company, Rate G-1, M.D.T.E. No. 130F; Commonwealth Electric Company, M.D.T.E. No. 330F; D.P.U. 88-135/151, at 210, 213-214 (Rate G-1 with two-step demand charge). For example, in the legacy Commonwealth Electric Company territory, Rates R-1, R-2 and G-1 all have multiple rate structures to account for customers that are deemed to have seasonal usage (Exh. DPU-10-3).

Eversource's MMRC proposal demonstrates that an average residential customer without an MMRC charge will be charged the same total amount as another average residential customer with an MMRC charge even though the non-MMRC customer will pay a customer charge and volumetric charge while the MMRC customer will be charged a customer charge, demand charge, and volumetric charge (Exh. ES-RDP-1, at 98). The Department finds that because the MMRC is designed as revenue neutral, it is appropriate for customers within the same class to have different charges.

(C) Impacts to Energy Efficiency

Some intervenors argue that the MMRC could potentially harm the Commonwealth's energy efficiency program because the reduced volumetric charge may weaken price signals to consumers to decrease energy consumption (Cape Light Compact Brief at 58; NECEC Reply Brief at 9; Vote Solar Reply Brief at 6). The Companies contend that rate proposals affecting demand are consistent with energy efficiency (Companies Reply Brief at 43).

The Green Communities Act, which establishes the Commonwealth's energy efficiency program, requires the acquisition of both energy efficiency and demand-reduction resources.[43] G.L. c. 25, § 21(b)(1). Further, the Department is obligated to consider the impacts of its rate design decisions, including the impact of new financial incentives on the successful development of energy efficiency. G.L. c. 164, § 141. The Department found that customers benefit from reductions in both energy consumption and peak demand through lower capacity and commodity prices. D.P.U. 17-05 Order at 409; see e.g., Three-Year Energy Efficiency Plans, D.P.U. 15-160 through D.P.U. 15-169, at 93 (2016); Bill Impacts of Energy Efficiency, D.P.U. 08-50-D at 11 (2012). The Department acknowledges that, while the reduced volumetric charge may weaken price signals for the kWh energy consumption component of energy efficiency, the demand charge component of the MMRC establishes a new price signal for demand reduction. Therefore, we find that the MMRC is not inconsistent with the Commonwealth's energy efficiency and demand reduction programs.[44] For further discussion of energy efficiency issues, refer to Section IV.G.2.c.

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43 An Act Relative To Green Communities, St. 2008, c. 169.

44 The Department has approved several demand response demonstration offerings proposed by the Program Administrators. See NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-178, at 44-45 (October 30, 2017); Fitchburg Gas and Electric Light Company, D.P.U. 16-184, at 18-19 (October 30, 2017); Three-Year Energy Efficiency Plans for 2016-2018, D.P.U. 15-160 through D.P.U. 15-169, at 141-143 (2016).

e. Exemptions

The Department may "exempt or modify" an MMRC for low-income ratepayers and any class or sub-class of Class I, Class II, or Class III net metering facilities that were in service not later than December 31, 2016. G.L. c. 164, § 139(j). The Companies do not seek to exempt either low-income ratepayers or any class or sub-class of Class I, Class II, or Class III net metering facilities that were in service not later than December 31, 2016 (Exhs. ES-RDP-1, at 85; DPU-46-5, at 2). The Companies' MMRC proposal applies to all host customers enrolled in Eversource's net metering tariffs and with a net metering facility electrified on or after January 1, 2019 (Exhs. ES-RDP-1, at 91; DPU-10-8; DPU-56-9, at 8 (Supp.). One intervenor and, in particular, one commenter, assert that the Department can create an exemption for low-income ratepayers to last in perpetuity (NECEC Brief at 38; Chairman Golden Comments to Secretary Beaton, June 13, 2017, at 1). The Green Communities Act states, in part, that "[i]n all decisions or actions regarding rate designs, the [D]epartment shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount." St. 2008; c. 169, § 78; G.L. c. 164, § 141. In consideration of these statutory provisions, the Department finds that there is public interest in exempting low-income host customers from an MMRC. Thus, the Department directs Eversource to modify all relevant tariffs, including Rate R-2 and Rate R-4, to include an MMRC exemption for low-income host customers.

f. MMRC Conclusion

The Department concludes that Eversource's MMRC proposal, modified so that it applies to customer accounts on December 31, 2018, meets the Act's procedural and statutory requirements. G.L. c. 164, § 139(j). The Department further finds that the Companies' MMRC results in just and reasonable rates. Low-income ratepayers that are host customers of net metering facilities shall be exempt from the MMRC. The Department requires the Companies to revise MMRC language in the relevant tariffs, including Residential Assistance Rates R-2 and R-4, and add an MMRC to the net metering tariff for effect February 1, 2018. The Department expects Eversource to file an MMRC education plan in an informational compliance filing by June 1, 2018. The Department strongly urges Eversource to work with stakeholders, including rate design intervenors, to design customer education tools, educational plans, and other guidance that address intervenor concerns before the June 1, 2018 informational filing.

g. Implementation

Having approved the MMRC as set forth above, we now address implementation. First, the MMRC may be added to electric bills for distribution utility accounts that receive Class I, Class II, Class III, or market net metering credits pursuant to G.L. c. 164, § 139(j). The Department recently conducted a rulemaking to implement An Act to Promote Energy Diversity in D.P.U. 17-10-A promulgating final net metering regulations to implement a small hydroelectric net metering program. Net Metering Rulemaking, D.P.U. 17-10-A (November 17, 2017); G.L. c. 164, § 139A; St. 2016, c. 188, § 10. The Department found that the small hydroelectric net metering program is distinct from the general net metering program and as such, facilities participating in the small hydroelectric net metering program are not considered Class I, Class II, or Class III facilities. D.P.U. 17-10-A at 9-10; 220 CMR 18.02. As such, an MMRC should not be imposed on facilities participating in the small hydroelectric net metering program.

Second, as discussed above, the Department directed the Companies to apply an MMRC to relevant customers with net metering facilities that go into service on December 31, 2018. As part of the Companies' June 1, 2018 informational filing, Eversource must include a plan to communicate with prospective net metering host customers to educate them about potentially becoming subject to an MMRC. The June 1, 2018 informational filing should specify that as of the date of this Order, a host customer that submits an application for interconnection services of a net metering facility may be subject to an MMRC. When the Companies file compliance tariffs to incorporate the MMRC, such tariffs should be filed for effect February 1, 2018, but indicate that: (1) the MMRC will not be applied to facilities that go into service prior to December 31, 2018; and (2) an MMRC may be applied to net metering facilities that go into service on or after December 31, 2018. The Department directs the Companies to include a section in the net metering tariff indicating that an MMRC may be applied to certain net metering facilities that go into service on or after December 31, 2018.

Third, in Section IV.D.5.c.ii, the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time. For the following C&I rate classes in the table below, the Department directs the Companies to include in their compliance filing an MMRC that sets the demand charge component based on their MMRC proposal (Exh. RR-DPU-49, Atts. (F) through (I)). The Department further directs the Companies to set the customer charge at the full unit cost and to set the kWh charge at the remaining amount for such C&I rate classes.

C&I Rate Classes that Require an MMRC

Service Area	Current Rate Classes
Boston	G-1
Boston	G-2
Boston	G-3
Boston	T-1
Boston	T-2
Cambridge	G-0
Cambridge	G-1
Cambridge	G-2
Cambridge	G-3
Cambridge	G-4
Cambridge	G-5
Cambridge	G-6
Commonwealth	G-1
Commonwealth	G-2
Commonwealth	G-3
Commonwealth	G-4
Commonwealth	G-5
Commonwealth	G-6
Commonwealth	G-7
WMECo	24
WMECo	G-0

WMECo	G-2
WMECo	T-0
WMECo	T-2
WMECo	T-4

The Department finds that an MMRC as directed herein for the C&I rate classes meets the rate structure goals of rate continuity, efficiency, and fairness.

F. Low-Income Discount

1. Introduction

a. Background

Pursuant to G.L. c. 164, § 1F, the Department requires distribution companies to provide percentage discounts to rates for low-income customers comparable to the low-income discount rate received off the total bill for rates in effect prior to March 1, 1998. See Expanding Low Income Customer Protections and Assistance, D.P.U. 08-4, at 36 (2008); D.P.U. 10-42/D.P.U. 10-43, at 1-2.

The Companies state that current low-income discounts vary depending on the legacy rate class to which the low-income customer takes service (Exh. ES-RDP-1, at 44). Eligible WMECo customers receive a 32-percent discount off their total bill (Exh. ES-RDP-1, at 44). For NSTAR Electric customers, low-income customers in the Boston Edison Company service territory receive discounts between 25.7 percent and 27.0 percent (Exh. ES-RDP-1, at 44). Low-income customers in the Cambridge Electric Light Company service territory receive discounts between 24.8 percent and 24.9 percent (Exh. ES-RDP-1, at 44).

Low-income customers in the Commonwealth Electric Company service territory receive discounts between 19.7 percent and 27.1 percent (Exh. ES-RDP-1, at 44).

The Companies state that the current average low-income monthly discount for an NSTAR Electric customer is $25.25, or 25 percent (Exh. LI-1-12). According to the Companies, the current average low-income monthly discount for a WMECo customer is $30.25, or 32 percent (Exh. LI-1-12).

b. Companies Proposal

In the Companies' initial rate design proposal, Eversource proposed a 30-percent low-income discount for NSTAR Electric customers and a 36-percent low-income discount for WMECo customers (Exh. ES-RDP-1, at 44). The Companies' initial and revised proposal relies on the method ordered by the Department in D.P.U. 15-155, which allows for a compensating adjustment to the low-income discount that includes the costs associated with the renewable portfolio standard ("RPS") solar carve out and the NMRS (Exhs. ES-RDP-1, at 44-45; ES-RDP-2, Sch. RDP-7).

According to the Companies' initial proposal, increasing the low-income discount to 30 percent for NSTAR Electric resulted in an additional revenue allocation of $7,471,279 to all other NSTAR Electric customers (Exh. ES-RDP-1, at 45). Furthermore, increasing the low-income discount to 36 percent for WMECo resulted in an additional revenue allocation of $4,010,786 to all other WMECo customers (Exh. ES-RDP-1, at 45). In the Companies' revised rate design proposal, Eversource proposed a uniform low-income discount of 36 percent for all eligible residential customers in both the WMECo and NSTAR Electric service territories (Exh. DPU-56-9, at 2 (Supp.)). No party commented on the Companies' proposal.

2. Analysis and Findings

Pursuant to Section 141, a fully compensating adjustment shall be made to the low-income discount where the scale of on-site generation would have an impact on affordability for low-income customers. D.P.U. 15-155, at 469. In D.P.U. 15-155, the Department determined that a fully compensating adjustment to the low-income discount would include only the costs associated with the RPS solar carve out and the NMRS, as these costs are directly related to the growth of on-site generation, and directed all electric distribution companies to file rate design proposals that comply with the standard set forth in Section 141. D.P.U. 15-155, at 470-471.

Based on our review of the record, the Department finds that on-site generation in the Companies' service territories has grown with an increase in costs from associated incentives that the Companies include in customers' bills, including bills of low-income customers (Exhs. ES-RDP-2, Sch. RDP-7 (East); ES-RDP-2, Sch. RDP-7 (West)). Thus, low-income customers have experienced an increase in bills as a result of the growth of on-site generation. Therefore, pursuant to Section 141 and the Department's directive in D.P.U. 15-155, the Department finds the Companies' revised proposal to adjust the low-income discount is appropriate. The adjusted low-income discount of 36 percent will remain in effect until the Companies' next base rate case, at which time the Department will determine whether further adjustment is warranted.

G. Other Base Distribution Rate Design Issues

1. Municipal Net Metering Credit Reduction

a. Introduction

Eversource proposed to assign all NSTAR Electric C&I customers to a single set of rate classifications and to assign all WMECo C&I customers to a single set of rate classifications (Exh. ES-RDP-1, at 51). As part of its proposed rate consolidation, the Companies planned to eliminate legacy rate classes and consolidate Rates T-1/B-5 and A-9 into the new Rate G-1 (Exhs. ES-RDP-1, at 22; ES-RDP-4, Sch. RDP-2 (East); DPU-67-2).[45] Under the proposed consolidation of Rates T-1/B-5 and A-9, the value of net metering credits generated by net metering facilities under such rate classes will decrease, including those generated by municipal net metering facilities (Exh. DPU-67-7, Att.). Investments in renewable generating facilities sometimes depend upon financing agreements and private contracts between distribution customers and third parties (Exh. TOB-1-1). Host customers of net metering facilities, including municipalities, may receive payments based on the expected output of the net metering facility generation for renewable energy credits, tax credits, or power purchase agreements (Exh. TOB-1-1).

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45 Boston Edison Company's optional TOU Rate T-1 includes a sub-rate class called B-5 and is available to non-residential customers whose load for billing purposes does not exceed or is estimated not to exceed ten kW (see Exh. DPU-67-8, Att.; M.D.T.E. No. 133F). Throughout this section, we refer to this legacy rate class as Rate T-1/B-5. Boston Edison Company's Rate G-1 includes a non-demand sub-rate class called A-9 (see Exh. DPU-67-8, Att.). Rate G-1/A-9 is available for all non-residential customers with single-phase service not exceeding 100 amperes and whose load for billing purposes does not exceed or is estimated not to exceed ten kW (M.D.T.E. No. 130F). Throughout this section, we refer to this legacy sub-rate class as Rate A-9.

b. Positions of the Parties

As set forth above in Section IV.D.5.c.ii, the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time. As such, the Companies' current C&I rate classes will remain unchanged. Therefore, it is unnecessary to set forth detailed arguments made by the parties regarding municipal net metering credit reduction.

The Attorney General maintains that there will need to be a plan for future consolidation of Rates T-1/B-5 and A-9, and she recommends closing the T-1/B-5 and A-9 rate classes to new customers or net metering facilities (Attorney General Brief at 26). The Attorney General suggests that as the Companies work toward rate consolidation in the future, they keep in mind the concept of gradualism and seek the input of the Municipalities and other stakeholders in preparation for the Companies' next rate case (Attorney General Brief at 26). Barnstable, Cambridge, CVEC, DOER, the Municipalities, TEC, and UMass request that the Department grandfather existing municipal net metering customers that have renewable energy contracts (Barnstable Brief at 3, 22; Cambridge Brief at 10; CVEC Brief at 20-21; DOER Brief at 14; Municipalities Brief at 1; TEC Brief at 22; UMass Brief at 18). NECEC recommends that the Department deny Eversource's proposed rate class alignment and consolidation (NECEC Brief at 8). Eversource argues that creating an exemption for the Municipalities is discriminatory because it would give special treatment to the Municipalities and not other customers who are facing the same rate changes (Companies Reply Brief at 46, 50).

c. Analysis and Findings

As stated above in Section IV.D.5.c.ii, the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time. Therefore, intervenors' concerns are moot regarding the impacts to net metering credit values resulting from the Companies' proposed changes to the C&I rates, specifically the proposal to consolidate Rates T-1/B-5, and A-9 and transition to the new Rate G-1.[46]

We also note that in this proceeding, the Municipalities stated that Eversource should consider the impact of the Companies' proposed rate changes on existing municipal private contracts to support the development of net metering facilities (Exhs. 1-MS-1, at 3-6; 1-JWM-1, at 6-8; ARLINGTON-1, at 5-6; NEWT-1, at 4-10; WEST-1, at 4-6). Eversource responded that it is not privy to the terms of the private contracts, nor would it be feasible for the Companies to review such agreements (Exh. TOB-1-1). Therefore, the Companies maintain that they are unable to assess the viability of municipal net metering projects under private contract based on net metering credits alone (Exh. TOB-1-1). The Department agrees with Eversource that it would be difficult for the Companies to evaluate the impacts of proposed rate design changes in the context of private financial contracts, nor is it

46 The following municipalities have net metering facilities that take service under Rate T-1/B-5 and Rate A-9: Acton, Arlington, Ashland, Bedford, Bellingham, Boston, Brookline, Burlington, Canton, Carlisle, Chelsea, Dedham, Dover, Framingham, Holliston, Hopkinton, Lexington, Lincoln, Maynard, Medfield, Medway, Millis, Milton, Natick, Needham, Newton, Norfolk, Sharon, Sherborn, Somerville, Stoneham, Sudbury, Walpole, Waltham, Watertown, Wayland, Weston, Westwood, Winchester, and Woburn (Exh. ES-RDP-12, at 48, M.D.P.U. No. 500, Appendix C).

Eversource's responsibility to take each of these individual contracts into consideration. We also agree that for the purposes of rate design, the Department's consideration of customer bill impacts excludes the impacts to customer revenues, such as revenues from net metering credits, and includes impacts to customer payments. Furthermore, when municipalities or other customers make financial decisions regarding net metering, such customers should assume that rates underlying net metering credits will change and not remain the same in perpetuity. Section 94 (electric distribution companies shall file schedules of rates not less frequently than every 5 years).[47] Therefore, the Department puts all customers taking net metering services, as well as net metering stakeholders, on notice that although the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time, it is possible that the current value of net metering credits will decrease in the future as rate design evolves.

Nonetheless, the Department recognizes that Eversource's proposed C&I rate consolidation would have had a potentially significant impact on certain municipal net metering facilities supported by the Commonwealth's renewable energy policy. The Department is required to consider the impacts of rate changes on the successful development of energy efficiency and on-site generation. Section 141. In light of this obligation and multiple intervenors' strong concerns about the impacts of the proposed rate consolidation on

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47 We cannot find that customers or third parties have a legitimate expectation that rates set in a third-party contract can supersede the rates established by the Department for a jurisdictional company pursuant to Section 94 or G.L. c. 164, § 93. See, e.g., Union Dry Goods Company v. Georgia Public Service Corporation, 248 U.S. 372, 375-376 (1919).

net metering customers, including municipal customers, we expect Eversource to take these impacts into consideration when planning for future rate consolidation and alignment. Therefore, the Department strongly encourages Eversource to work with potentially negatively-affected customers to mitigate these concerns prior to filing its next revenue neutral rate redesign or base rate proceeding. Furthermore, to the extent that customers have questions about how proposed rate consolidation and alignment affects their bills, including impacts to revenues such as net metering credits, the Department expects Eversource to communicate effectively with its customers and respond fully to all inquiries.

Finally, in reviewing the Companies' plan to eliminate legacy rate classes and consolidate Rates T-1/B-5 and A-9 into the new Rate G-1, the Department credits evidence that all 40 customers in Rate T-1/B-5 are net metering customers (Exhs. NEWT-1; NEWT-2). To limit the potential impacts of future rate design proposals, the Department finds that the Companies should close Rate T-1/B-5 to all new customers effective February 1, 2018. Therefore, the Department directs the Companies to close Rate T-1/B-5 to new customers and update the Rate T-1 tariff, proposed M.D.P.U. No. 133G, accordingly (RR-DPU-51, Att. (a) at 362).

2. <u>C&I Non-Coincident Peak Demand Charges</u>

a. <u>Introduction</u>

Eversource currently bills customers a monthly demand charge on the basis of a customer's highest usage at a single point in time, or a customer's non-coincident peak demand (Exh. ES-RDP-1, at 12, 14-15).[48] Eversource offers the following C&I rate classes that include a demand charge: Boston Edison Company Rate G-1, to customers with three-phase service or with single-phase service exceeding 100 amperes, Rate G-2, Rate G-3, and Rate T-2 (M.D.T.E. Nos. 130F, 131F, 132F, 134F); Cambridge Electric Light Company's Rate G-1, Rate G-2, Rate G-3, and Rate G-4 (M.D.T.E. Nos. 231G, 232G, 233G, 234G); Commonwealth Electric Company's Rate G-1, Rate G-2, Rate G-3, Rate G-4 (M.D.T.E. Nos. 330F, 331F, 332F, 333F); and WMECo's Rate 24, Rate G-0, Rate T-0, Rate G-2, Rate T-4, Rate T-2, and Rate T-5 (M.D.P.U. Nos. 1003W, 1004W, 1005W, 1006W, 1007W, 1008W, 1049B). Also, Eversource offers the following non-demand C&I rate classes to customers: (a) Boston Edison Company Rate G-1, to customers with single-phase service not exceeding 100 amperes, Rate T-1 (M.D.T.E. Nos 130F, 133F); (b) Cambridge Electric Light Company's Rate G-0, Rate G-5, and Rate G-6 (M.D.T.E. Nos. 230G, 235G, 236G); (c) Commonwealth Electric Company's Rate G-5 and Rate G-6 (M.D.T.E. Nos. 334F, 335F); and (d) WMECo's Rate 23 (M.D.P.U. No. 1002W)).

The Companies' proposed demand charge rates effective January 1, 2018 vary by legacy company and rate class (RR-DPU-50, Att. (f) at Exhs. ES-RDP-3 (ALT1), Sch. RDP-1 (East); ES-RDP-3 (ALT1), Sch. RDP-1 (West)). All of the Companies' proposed aligned C&I rate classes for effect January 1, 2019 include a distribution demand

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48 Several of the Companies' legacy C&I rate classes include a demand charge, although the first 2 kW or 10 kW may be exempt from billed demand charges (RR-DPU-50, Att. (e) at Exhs. ES-RDP-3 (ALT1), Sch. RDP-1 (East); ES-RDP-3 (ALT1), Sch. RDP-1 (West)).

charge, except for Rate G-1 (non-demand) (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-5).

b. Positions of the Parties

i. Acadia Center

Acadia Center argues that non-coincident peak demand charges do not meet the Department's rate design principles of cost causation, efficiency, and fair allocation of costs (Acadia Center Brief at 15, citing Exh. AC-ML-1, at 25; Acadia Center Reply Brief at 8). Further, Acadia Center contends that the distribution system is not designed to meet the individual non-coincident peak demand of any one small C&I customer, and one customer does not cause more localized distribution peaks (Acadia Center Brief at 16, citing Exh. AC-ML-1, at 26; Tr. 16, at 3227; Acadia Center Reply Brief at 8, citing Tr. 16, at 3278). Acadia Center maintains that diversity of demand means that the distribution system is built for the joint peak at each node (Acadia Center Brief at 8). Thus, Acadia Center argues that demand charges based on non-coincident peak demand are unlikely to be correlated with the peak demand that causes system costs (Acadia Center Brief at 16; Acadia Center Reply Brief at 8).

Moreover, Acadia Center argues that Eversource has failed to establish that small C&I customers understand and can manage demand charges (Acadia Center Brief at 14, citing D.P.U. 15-155, at 459; Acadia Center Brief at 15; Acadia Center Reply Brief at 8). In support of its position, Acadia Center maintains that the Companies neither surveyed small C&I customers to determine their knowledge of demand charges nor prepared a customer education plan for them (Acadia Center Brief at 15, citing Tr. 17, at 35). Further, Acadia Center alleges that the Companies will not provide small C&I customers with a real-time demand monitor (Acadia Center Brief at 15, citing Tr. 16, at 3305). Acadia Center alleges that small C&I customers are faced with issues that do not lend themselves to actionable price response, such as their electric water heaters running simultaneously with other high-demand equipment (Acadia Center Brief at 15).

Accordingly, Acadia Center argues that demand charges are inappropriate for small C&I customers and, therefore, the Department should reject them (Acadia Center Brief at 14; Acacia Center Reply Brief at 8). Further, Acadia Center recommends that the Department direct Eversource to create a rate class for new and existing small C&I customers that, absent the customer charge, is billed solely a volumetric rate (Acadia Center Brief at 16, citing Exh. AC-ML-1, at 27; D.P.U. 15-155, at 479-480). According to Acadia Center, a fully volumetric rate for small C&I customers would protect them, provide them understandable price signals to make informed decisions, and promote energy efficiency (Acadia Center Brief at 16, citing Exh. AC-ML-8, at 2).

ii. Cape Light Compact

Cape Light Compact opposes demand charges for small C&I customers (Cape Light Compact Brief at 72; Cape Light Compact Reply Brief at 14). Cape Light Compact argues that non-coincident peak demand charges for small C&I customers violate the rate design principles of simplicity and efficiency (Cape Light Compact Brief at 72).

According to Cape Light Compact, Eversource did not: (1) determine whether small C&I customers are able to understand and adapt to demand charges; (2) develop an education plan on demand charges; or (3) provide data on small C&I monthly energy and demand use (Cape Light Compact Brief at 72, citing Tr. 17, at 3510-3513; Cape Light Compact Reply Brief at 14). Thus, Cape Light Compact argues that demand charges are punitive and burdensome to customers with low annual kWh usage and occasional high demand (Cape Light Compact Brief at 72).

Further, Cape Light Compact maintains that demand charges provide customers with less cost control on their bills and provide a signal for inefficient behavior (Cape Light Compact Brief at 72, citing Exh. CLC-JFW-1, at 18; Cape Light Compact Reply Brief at 14). Cape Light Compact adds that demand charges reduce the incentive for customers to install energy efficiency measures and to reduce their electricity consumption, and, therefore, the Companies' demand charge proposal ignores Department precedent (Cape Light Compact Brief at 14-15, citing D.P.U. 15-80/15-81, at 295; D.P.U. 10-70, at 332).

Moreover, Cape Light Compact maintains that, although the Companies assert that the Department has approved demand charges for every distribution company's C&I customers, approximately 30,000 Commonwealth Electric Rate G-1 customers take service on non-demand rates (Cape Light Compact Brief at 14, citing Exh. ES-RDP-4, Sch. RDP-2 (East)). Therefore, Cape Light Compact recommends that the Department reject any demand charge proposed for small C&I customers (Cape Light Compact Brief at 79, 81).

iii. NECEC

According to NECEC, the Companies' proposed non-coincident peak demand charge for small C&I customers weakens the alignment between costs and rates and is not reflective of cost causation (NECEC Brief at 11, citing Exhs. ES-RDP-2, Sch. RDP-5; ES-RDP-4, Sch. RDP-2; NECEC Reply Brief at 3). NECEC maintains that a non-coincident peak demand charge is inappropriate because distribution costs are driven by coincident peaks (NECEC Brief at 11, citing Exhs. CLC-JFW-1, at 16; SREF-TW/MW-1, at 22-23; UMASS-RS-1, at 21; VS-NP/RG-1, at 35).

Moreover, NECEC alleges that stand-alone net metering customers do not contribute to consumptive demand on the Companies' system, and, instead, they provide demand-related benefits (NECEC Brief at 12, citing Exh. SREF-TW/MW-1, at 32 (Supp.)). Therefore, NECEC contends that it is illogical and counterproductive to move customers with distributed generation that are currently on time-varying rates to new rate classes with demand charges (NECEC Brief at 12, citing Exh. SREF-TW/MW-1, at 32 (Supp.)). Accordingly, NECEC argues that moving customers from a time-varying rate to a rate class with a demand charge may impose unjustified financial consequences and create "meaningless" price signals (NECEC Brief at 12-13, citing Exh. SREF-TW/MW-1, at 33 (Supp.); NECEC Reply Brief at 3-4, citing Exhs. AC-ML-1, at 26-28, 30; CLC-JFW-1, at 16; SREF-TW/MW-1, at 7-8, 22-23; SREF-TW/MW-1, at 14, 35 (Supp.); SREF-TW/MW-1 (Surr.) at 10-12; UMASS-RS-1, at 22; VS-NP-1, at 32-33, 35).

iv. Sunrun and EFCA

According to Sunrun and EFCA, the Companies proposed a rate design that includes a non-coincident peak demand charge for small C&I customers (Sunrun and EFCA Brief at 11, citing Exh. ES-RDP-1, at 85). Sunrun and EFCA allege that the Department rejected a similar proposal on demand charges in National Grid's most recent rate case (Sunrun and EFCA Brief at 12, citing D.P.U. 15-155, at 457-458).

First, Sunrun and EFCA allege that the Companies' non-coincident peak demand charge proposal contradicts the Department's finding that "although pricing distribution service on demand use may support the cost to serve principle; it is not the best rate structure to promote energy efficiency," because Sunrun and EFCA claim that Eversource states that: (1) demand charges more accurately represent a customer's use of the distribution system than energy charges do; and (2) distribution system planning is based on facilities that service the maximum demand from each customer (Sunrun and EFCA Brief at 12-13, citing Exh. ES-RDP-1, at 14-15; D.P.U. 15-155, at 459). Second, Sunrun and EFCA argue that the Companies' non-coincident peak demand charges contradict the Department's finding that non-energy charges "distort incentives to conserve electricity, may unfairly impose higher costs on certain customers, and discourage customers from investing in cost-effective energy efficiency" (Sunrun and EFCA Brief at 13, citing D.P.U. 15-155, at 459). Specifically, Sunrun and EFCA argue that Eversource's proposal is intended to increase cost recovery and not to incentivize certain customer actions (Sunrun and EFCA Brief at 13, citing Tr. 18, at 3573-3577). Third, Sunrun and EFCA maintain that Eversource did not design an education or outreach program and failed to evaluate customers' knowledge of demand charges, even though Sunrun and EFCA claim that the Department rejected National Grid's demand charge-based proposal for the same reasons in D.P.U. 15-155 (Sunrun and EFCA Brief at 13-14, citing D.P.U. 15-155, at 459-460; Exh. ES-RDP-Rebuttal-1, at 1-13; Tr. 17, at 3510-3511). Finally, Sunrun and EFCA contend that Eversource's non-coincident peak demand charge proposal does not include meters that can record the time and date of a customer's maximum demand, which Sunrun and EFCA allege contradicts the Department's finding in D.P.U. 15-155 that customers should have the ability to monitor electricity consumption in real time in order for a company to implement non-coincident peak demand charges (Sunrun and EFCA Brief at 14-15, citing D.P.U. 15-155, at 460; Tr. 16, at 3305, 3354-3355). Accordingly, Sunrun and EFCA assert that customers will not know when they are using two demand-intensive appliances, such as a clothes dryer and an electric water heater, at the same time (Sunrun and EFCA Brief at 15).

Further, Sunrun and EFCA argue that the Companies did not provide information on the customer bill impacts of a 15-minute demand interval for rate classes that do not have demand charges (Sunrun and EFCA Brief at 15).[49] Moreover, Sunrun and EFCA claim that, although the Companies allege that their rate design will support storage, Eversource did not offer proof with any studies or any supporting evidence (Sunrun and EFCA Brief at 16, citing Tr. 16, at 3378, 3384; Sunrun and EFCA Brief at 17).

49 When demand is measured at 15-minute intervals, the demand meter captures a customer's highest usage in any 15-minute period (Exh. ES-RDP-1, at 14).

Sunrun and EFCA claim that non-coincident peak demand charges "fl[y] in the face of all conventional wisdom" because a utility's consumption at system peak determines the amount of capacity that it must have available, not consumption at a customer's peak (Sunrun and EFCA Brief at 15, citing NARUC Manual on Distributed Energy Rate Design and Compensation/The Economics of Regulation, Alfred Kahn). Therefore, Sunrun and EFCA recommend that the Department reject the Companies' non-coincident peak demand charge proposal because it "lacks a sufficient basis" for approval (Sunrun and EFCA Brief at 16, 17).

v. Vote Solar

Vote Solar argues that demand charges billed to small C&I customers violate the Department's ratemaking principles of simplicity and fairness (Vote Solar Brief at 16). According to Vote Solar, a non-coincident peak demand charge is not an appropriate determinant of cost causation for small C&I customers because their consumption does not alter the local distribution system peak (Vote Solar Brief at 17, citing Exh. VS-NP-RRD-Surrebuttal-1, at 6). Moreover, Vote Solar maintains that small C&I customers do not understand demand charges (Vote Solar Brief at 17, citing Exhs. VS-NP/RG-1, at 31-33; AC-ML-1, at 25; Vote Solar Reply Brief at 7). According to Vote Solar, the Companies did not conduct a survey of small C&I customers to determine their knowledge of demand charges and did not develop an education plan for their edification (Vote Solar Brief at 17, citing Tr. 17, at 3511). Therefore, Vote Solar alleges that small C&I customers that are billed a non-coincident peak demand charge do not have an incentive to reduce their demand during peak periods, and the Companies are forgoing the opportunity to encourage their customers to reduce generation, transmission, and distribution costs, as well as to lower future costs by avoiding construction of additional infrastructure (Vote Solar Reply Brief at 7).

Further, Vote Solar claims that Eversource did not design non-coincident peak demand charges for small C&I customers to allow the Companies to recover the cost of providing service, because the Companies do not incur costs based on non-coincident peak demand (Vote Solar Reply Brief at 6-7, citing D.P.U. 12-25, at 444-445). According to Vote Solar, a non-coincident peak demand charge does not incentivize customers to modify their usage behavior to promote savings to the system overall (Vote Solar Reply Brief at 7). Accordingly, Vote Solar argues that the Companies' sole focus on rate design as a vehicle for cost recovery is misplaced and it purports that rate design should also promote energy efficiency (Vote Solar Reply Brief at 7). Therefore, Vote Solar maintains that the Department should deny demand charges for small C&I customers (Vote Solar Brief at 17).

vi. Companies

Eversource argues that the Department should reject arguments of Acadia Center, Cape Light Compact, NECEC, Sunrun and EFCA, and Vote Solar (Companies Brief at 41, 42; Companies Reply Brief at 23, 25, 32, 44, 51-52). The Companies maintain that demand charges for small C&I customers do not violate the rate design principles of simplicity and efficiency (Companies Brief at 41).

According to the Companies, the Department has approved C&I demand charges for many years, and the Companies have implemented rate structures that include demand charges for small C&I customers for decades (Companies Brief at 41; Companies Reply Brief at 23, citing Exh. ES-RDP-Rebuttal-1, at 24-25 (August 22, 2017)). Eversource maintains that it currently bills a demand charge for 64,333 out of 64,513 customers that it proposes to transfer to the new aligned Rate G-1 (Companies Brief at 41, citing Exh. ES-RDP-2 (ALT1), Sch. RDP-2, at 2 (East); Companies Reply Brief at 23-24 n.11; 30, citing Exh. ES-RDP-2 (ALT1), Sch. RDP-2, at 2 (East)).[50] Further, Eversource adds that it evaluated bill impacts and proposed a mitigation plan to address the effect of moving a small number of customers taking service on legacy rate classes without demand charges to aligned rate classes that include a demand charge (Companies Reply Brief at 4). Eversource also notes that every electric distribution company in Massachusetts utilizes rate structures with a demand charge (Companies Brief at 41, citing Exh. ES-RDP-Rebuttal-1, at 24-25 (August 22, 2017)). Therefore, the Companies assert that there is no evidence showing that small C&I customers do not understand demand charges (Companies Reply Brief at 23, 30).

Moreover, the Companies allege that demand charges send the correct price signals to customers because Eversource constructed its distribution system on the basis of meeting

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50 In response to Cape Light Compact's claim that approximately 30,000 Rate G-1 customers are not currently taking service on a demand rate, Eversource responds that it proposes to move the approximately 30,000 legacy Rate G-1 customers in the Commonwealth Electric Company territory without demand meters to the new aligned Rate G-1 (non-demand) rate class (Companies Reply Brief at 24, citing Exh. ES-RDP-4, Sch. RDP-2 (East)).

capacity and not volumetric throughput (Companies Brief at 41, citing Exh. ES-RDP-2 (ALT1), Sch. RDP-2, at 25 (East)). Eversource claims that its distribution costs are driven by a variety of demand measures (Companies Reply Brief at 52). According to the Companies, distribution assets close to the customers' load are more closely correlated with customer non-coincident peak demand, while assets further from the customers' load (e.g., substations) are more closely correlated with aggregated measures of demand (Companies Reply Brief at 52). Moreover, the Companies maintain that their assets were constructed to serve their customers' loads and the costs for these assets cannot be avoided through a reduction in kWh (Companies Brief at 41). According to Eversource, billing customers based on volumetric usage sends the least efficient price signal for distribution service and does not reflect cost causation because kWh usage does not inform distribution system planning (Companies Brief at 42; Companies Reply Brief at 44). Further, the Companies claim that energy charges are not a better measure than demand charges of the costs for all components of the distribution system (Companies Reply Brief at 52). Eversource argues that per-kWh rates provide an inexact price signal to a customer affording the same incentive to reduce load at midnight or at 6:00 p.m. (Companies Reply Brief at 52).

In response to Vote Solar's argument that demand charges based on non-coincident peak demand are not appropriate for determining cost causation, the Companies assert that Vote Solar's argument is inaccurate because, they claim, there is no advantage of a demand charge based on coincident peak for recovering base distribution costs (Companies Brief at 41, citing Exh. DPU-60-3). Further, Eversource contends that NECEC, Sunrun and

EFCA, and Vote Solar's definition of coincident peak confuses this issue (Companies Brief at 41). According to the Companies, these intervenors define coincident peak as the peak demand that occurs relative to the local distribution system peak (Companies Brief at 41). Eversource maintains that coincident peak is defined as the peak demand at the time of aggregate distribution system peak (Companies Brief at 41). The Companies argue that they do not meter customers on the basis of local distribution peaks or rate class peaks because it is not practical, and Eversource adds that if it did, customers would be charged based on a complex array of location-based rates that would be difficult to understand and respond to (Companies Brief at 42; Companies Reply Brief at 43).

Further, the Companies assert that billing customers based on coincident peak demand does not provide efficient price signals to customers because customers do not know when the coincident peak demand occurs (Companies Brief at 42). However, the Companies argue that customers have direct control over their individual peak demand, and, therefore, non-coincident peak demand charges do not reduce a customer's ability to control its electric bill (Companies Brief at 42; Companies Reply Brief at 23). Moreover, the Companies add that demand charges do not reduce incentives to invest in conservation and energy efficiency measures because lower wattage appliances reduce both demand and energy (Companies Reply Brief at 23). Therefore, Eversource argues that a demand charge provides a price signal to customers to base decisions regarding efficient use and bill management (Companies Reply Brief at 23).

In response to the claim that the Department's decision in D.P.U. 15-155 regarding demand charges for small C&I customers should apply here, Eversource argues that it distinguishes its proposed, aligned Rate G-1 demand rate structure from National Grid's proposal (Companies Reply Brief at 51, citing D.P.U. 15-155, at 459). According to the Companies, National Grid proposed to bill demand charges to small C&I customers that had not previously been billed a demand charge (Companies Reply Brief at 51). Conversely, Eversource maintains that it proposes to continue to bill small C&I customers a demand charge (Companies Reply Brief at 51). Moreover, National Grid proposed customer charges and not a demand charge (Companies Reply Brief at 40). Further, the Companies assert that if they were to eliminate the demand charge for some small C&I customers, these customers would experience significant bill impacts if they have load factors greater than the class average (Companies Reply Brief at 51-52).

For these reasons, Eversource maintains that non-coincident peak demand is the appropriate billing determinant for demand charges (Companies Reply Brief at 52). The Companies allege that rate design balances several competing principles and no single rate design can perfectly reflect efficient and cost-based rates while also maintaining simplicity and gradualism (Companies Reply Brief at 44). Accordingly, Eversource explains that the Department must balance all of these guiding rate design principles as well as prevailing public policies (Companies Reply Brief at 44).

c. Analysis and Findings

As an initial matter, the Department notes that, contrary to assertions discussed above, National Grid did not propose demand charges for its residential and small C&I customers in D.P.U. 15-155. Rather, National Grid proposed tiered customer charges based on a customer's maximum kWh use in a billing month over the last twelve billing months for its residential and small C&I customers. D.P.U. 15-155, at 401-403. The customer charge tier would have been effective for twelve months and would not change based on the customer's actual maximum kWh use in each billing month. D.P.U. 15-155, at 401-403. Each tier was defined by a kWh consumption range and was intended to serve as a proxy for the customer's size based on the customer's estimated monthly maximum demand. D.P.U. 15-155, at 402. Since National Grid did not propose actual demand charges for its residential and small C&I customers, the Department's findings in that case do not apply to Eversource's demand charge proposal in this proceeding.

In Section IV.D.5.c.ii above, the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time. Therefore, existing rate designs for small C&I customers will remain the same. The Department has approved C&I demand charges for many years for Eversource's legacy companies, and the Companies have implemented rate structures that include demand charges for small C&I customers for decades (Exh. ES-RDP-Rebuttal-1, at 24-25 (August 22, 2017)). Western Massachusetts Electric Company, D.T.E. 06-55, at 21-22 (2006); Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, NSTAR Gas Company, D.T.E. 05-85, at 31 (2005). Moreover, Eversource estimates that 89,901 small C&I customers are not currently billed on a rate that includes a demand charge (Exh. AC-1-16).[51] Therefore, it is not necessary for these customers to receive a targeted education plan because small C&I customers without demand charges will not be billed demand charges under the approved rate design, and small C&I customers that have been billed demand charges for decades will continue to be billed demand charges based on their existing rate structures.

Further, while these non-coincident peak demand charges have been in existence for small C&I customers for decades, Eversource has achieved an award winning energy efficiency program (Tr. 2, at 353-356). Eversource leads the nation in executing its energy efficiency programs, and its customers receive savings from these programs at unprecedented rates (Tr. 2, at 391). Accordingly, the existence of demand charges has not inhibited the Companies from successfully implementing energy efficiency programs that provide savings to their customers. Moreover, energy efficiency programs may seek to reduce peak demand as well as usage, and energy efficiency cost-benefit analyses account for the economic benefit of reductions in both peak demand and energy (Exh. ES-RDP-Rebuttal-1, at 27 (August 22, 2017)). Further, the three-year, statewide energy efficiency plan regarding specific actions for the 2016 through 2018 term identifies demand reduction initiatives as a beneficial resource. Three-Year Energy Efficiency Plans, D.P.U. 15-160 through D.P.U. 15-169, at 142 (2016); see G.L. c. 25, § 21(b)(1).

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[51] Boston Edison Company's Rate G-1; Cambridge Electric Light Company's Rate G-0, Rate G-5, and Rate G-6; Commonwealth Electric Company's Rate G-1, Rate G-5, and Rate G-6; and WMECo's rate classes Rate 23, G-0 (Exh. AC-1-16).

Demand charges comprise an efficient rate structure that distinguishes between those costs that vary with changes in the energy delivered and those costs that vary with plant capacity, which are driven by peak demand on circuits (Exh. ES-RDP-Rebuttal-1, at 24-45 (August 22, 2017)). D.P.U. 10-70, at 332. For all these reasons, the Department finds that demand charges for Eversource's small C&I customers are consistent with Department ratemaking goals (Exh. ES-RDP-Rebuttal-1, at 24-25 (August 22, 2017)). The Department evaluates compliance with Section 141 by rate class in Section IV.K below.

3. Determination of Billing Demand

a. Introduction

Eversource proposes to eliminate kilovolt-ampere ("kVA") demand billing (Exh. ES-RDP-1, at 25). Currently, WMECO bills exclusively using kWs, while NSTAR Electric typically uses kW billing for the small C&I use customers and kVA billing for its large customers. (Exh. ES-RDP-1, at 25).[52] The Companies cannot bill NSTAR Electric's small C&I customers and any of WMECo's customers for demand using kVA because these customers' meters lack the capability of measuring demand in kVA (Exh. ES-RDP-1, at 25-26). The Companies propose to establish kW billing demand as a uniform standard across the Eversource system (Exh. ES-RDP-1, at 25-26).

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[52] NSTAR Electric's demand billing based on kVA requires customers to pay for the cost of their power factor requirement (Tr. 17, at 3442). At its simplest level, power factor is the ratio of the power that an electrical device draws from the main supply and the power that it actually consumes. Power factor is the ratio of a customer's kW to kVA (Tr. 17, at 3442). An ideal power factor is 1.0. A power factor less than 1.0 might be the result of the electrical device, such as inductive motors or florescent lights, operating out of phase with the utility's distribution system.

The Companies propose a power factor correction provision for the proposed aligned Rate G-2, Rate G-3, and Rate G-4 (RR-DPU-51, Att. (c) at 20, 24, 27). The provision states: "If a [c]ustomer is found to have a power factor less than 90 [percent] lagging, the Company may require correction to at least 90 [percent] lagging as a condition of service. If the [c]ustomer does not correct the power factor to at least 90 [percent] lagging and the Company corrects the condition, the customer will reimburse the Company for all costs which it incurs." (RR-DPU-51, Att. (c) at 20, 24, 27).

b. Positions of the Parties

i. TEC

TEC recommends that the Department retain kVA demand billing (TEC Brief at 6; TEC Reply Brief at 9). According to TEC, removing kVA demand billing will result in poor outcomes for the distribution system, ratepayers, and the Companies (TEC Brief at 5-6; TEC Reply Brief at 9).

According to TEC, low power factor customers are typically those with inductive loads (e.g., heavy motors or pumps), that require a greater amount of distribution system capacity reactive power, and that incur greater losses caused by the difference between real power (measured in kW) and apparent power (measured in kVA) (TEC Brief at 6). TEC explains that a customer with a low power factor draws more current from the distribution system than a customer with a high power factor holding the amount of power consumed constant (TEC Brief at 6). Thus, TEC argues that low power factor customers cause higher costs on the distribution system (TEC Brief at 6).

Moreover, TEC contends that billing demand based on kVA incentivizes customers to correct their power factor without encouragement from the Companies and thereby reduces costs for all ratepayers (TEC Brief at 6). TEC asserts that kVA demand billing is appropriate to avoid cross subsidies (TEC Brief at 7). According to TEC, many NSTAR Electric customers have invested in equipment to improve their power factors because the kVA demand billing compelled them to do so (TEC Brief at 6). TEC argues that these investments will become stranded assets because customers will no longer receive a financial benefit from them (TEC Brief at 7).

Further, TEC contends that the Companies admitted that eliminating kVA demand billing is not ideal, but a necessary requirement to move all customers across NSTAR Electric and WMECo to the same platform because kVA demand billing is not available for WMECo (TEC Brief at 7, citing Tr. 17, at 3432-3433; TEC Reply Brief at 9, citing Tr. 17, at 3442-3443). However, TEC argues that the Companies' explanation does not alone justify its proposal to eliminate kVA demand billing (TEC Brief at 7). Moreover, TEC alleges that kVA demand billing is an incremental source of revenue for the Companies that they will forego when implementing kW demand billing system-wide (TEC Brief at 7). For all these reasons, TEC recommends that the Department reject the Companies' proposal to eliminate kVA demand billing (TEC Brief at 6, 7; TEC Reply Brief at 9).

ii. Companies

According to the Companies, TEC's recommendation to retain kVA demand billing is impractical (Companies Reply Brief at 29, citing TEC Reply Brief at 9). Eversource maintains that WMECo lacks the kVA data to align rates (Companies Reply Brief at 29). According to the Companies, they would have to maintain legacy rate classes to continue kVA demand billing (Companies Reply Brief at 29). Further, Eversource contends that there is no evidence showing the bill impacts to customers on an intra-class basis of retaining kVA demand billing (Companies Reply Brief at 29).

c. Analysis and Findings

In Section IV.D.5.c.ii above, the Department directed the Companies to retain their legacy C&I rate classes at this time. Therefore, the Companies' proposal to establish kW billing demand as a uniform standard across the Eversource system is moot because the Companies need not eliminate kVA billing in the instant case. Accordingly, Eversource is directed to continue to bill for demand using its current methods.

4. Time of Use Rate Design

a. Introduction

i. Time of Use Peak Period

Eversource's current TOU periods vary by legacy service territory (Exh. ES-RDP-1, at 26). WMECo currently uses a 12 p.m. to 8 p.m. weekday peak period (Exh. ES-RDP-1, at 26). Boston Edison Company's weekday peak period is 9 a.m. to 6 p.m. in the summer and 8 a.m. to 9 p.m. in the winter (Exh. ES-RDP-1, at 26). Cambridge Electric Light

Company and Commonwealth Electric Company use a 9 a.m. to 6 p.m. weekday peak period when Eastern Daylight Savings time is in effect and a 4 p.m. to 9 p.m. weekday peak period when Eastern Standard Time is in effect (Exh. ES-RDP-1, at 26). The Companies proposed to use 9 a.m. to 6 p.m. weekdays prevailing time as the peak period definition, applicable to their proposed consolidated and aligned C&I rate classes (Exh. ES-RDP-1, at 26).

Alternatively, TEC proposed a summer peak period of 1 p.m. to 7 p.m. and a winter peak period of 4 p.m. to 9 p.m., applicable to the Companies' proposed consolidated and aligned C&I rate classes (Exh. TEC-JB-1, at 5). According to TEC, its proposed peak TOU periods capture 100 percent of Eversource's monthly summer distribution system peak demands and more than 70 percent of Eversource's monthly winter distribution system peak demands (Exh. TEC-JB-1, at 5).

In Section IV.D.5.c.ii above, the Department directed the Companies to retain their legacy C&I rate classes at this time. Therefore, this issue is moot and it is unnecessary to set forth the arguments of the parties on this issue.

ii. Time of Use Rate Design

The Companies' current legacy rate classes include a variety of TOU rate design options (see, e.g., M.D.T.E. Nos. 123F, 133F). All of NSTAR Electric's residential customers may take service on an optional TOU rate, which includes a rate design with a higher per-kWh volumetric rate during each legacy company's defined peak period (M.D.T.E. Nos. 123F, 224G, 225G, and 325F). WMECo's residential customers do not currently have an available optional TOU rate. Some C&I customers take service under

TOU rates (Exh. ES-RDP-9, at 14-15). Boston Edison Company offers Rate T-1 (optional TOU) and Rate T-2 (TOU) (Exh. ES-RDP-9, at 14). Cambridge Electric Light Company offers Rate G-2 (TOU secondary service), Rate G-3 (TOU 13.8 kV service), Rate G-4 (optional TOU), and Rate G-6 (optional TOU) (Exh. ES-RDP-9, at 14). Commonwealth Electric Company offers Rate G-2 (medium TOU or large TOU secondary service), Rate G-3 (large TOU), and Rate G-7 (optional TOU) (Exh. ES-RDP-9, at 15).

b. Positions of the Parties

i. Acadia Center

Acadia Center maintains that the Department should approve time-varying rates for residential and small C&I customers (Acadia Center Brief at 20). According to Acadia Center, the Department already has signaled a future with time-varying rates (Acadia Center Brief at 20, citing D.P.U. 12-76-B; D.P.U. 14-04-C). Further, time-varying rates are under consideration in the pending grid modernization dockets (Acadia Center Brief at 20, citing Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-120 (grid modernization plan); Fitchburg Gas and Electric Light Company, D.P.U. 15-121 (grid modernization plan); D.P.U. 15-122).

Acadia Center asserts that properly designed time-varying rates provide savings to customers and optimize the electric system (Acadia Center Brief at 20). According to Acadia Center, low customer participation in the Companies' TOU rate classes is caused by the Companies' failure to effectively promote and explain these rates to customer (Acadia Center Brief at 20, citing Tr. 18, at 3605-3606). Acadia Center contends that The United

Illuminating Company, a Connecticut electric distribution utility, achieved 23-percent adoption of simple TOU rates for residential customers (Acadia Center Brief at 20, citing Exhs. AC-ML-6; AC-ML-1, at 29).

Acadia Center recommends that the Companies' existing TOU rates be redesigned according to the Department's rate design goals (Acadia Center Brief at 21, citing Exh. AC-ML-1, at 30-31). For example, Acadia Center argues that the Companies' proposed peak period for C&I customers is not aligned with cost-causation because the system peak sometimes falls outside the 9 a.m. to 6 p.m. peak window (Acadia Center Brief at 21, citing RR-WMIG-1). Acadia Center contends that this scenario may inadvertently encourage a higher peak usage (Acadia Center Brief at 21, citing Exh. AC-ML-1, at 31).

In response to the Companies' argument that distribution TOU rates are not appropriate because the peak and off-peak periods may conflict with peak and off-peak periods for energy supply, Acadia Center agrees, but recommends that, in the short term for simplicity purposes, the peak periods should be aligned between energy supply, transmission, and distribution (Acadia Center Reply Brief at 9, citing Exh. AG-ML-1, at 4). Acadia Center agrees with the peak period definition that WMIG and TEC recommend (Acadia Center Reply Brief at 9, citing TEC Brief at 10-14). Acadia Center contends that, in the long-run, TOU rates should be more granular and incent behavior of different types of customers at different locations (Acadia Center Reply Brief at 9, citing Exh. AC-ML-1, at 28). While Acadia Center makes this recommendation regarding its vision for long-run time-varying rates, it suggests that it is outside the scope of this proceeding (Acadia Center Brief at 9).

Further, Acadia Center maintains that the Department should carefully consider the Companies' proposed redesign of small C&I TOU rates to avoid undermining existing incentives for net metering customers (Exh. AC-ML-1, at 32-22). Acadia Center argues that Eversource's proposals to eliminate TOU rates and replace them with rate designs that include demand charges "are a damaging step backwards" (Acadia Center Brief at 20, citing Exh. AC-ML-1, at 28, 31-32). Accordingly, Acadia Center recommends that the Department direct the Companies to offer an opt-in TOU rate for residential and small C&I customers (Acadia Center Brief at 20).

ii. NECEC

NECEC recommends that Eversource retain all current optional TOU rates for all rate classes (NECEC Brief at 8). NECEC argues that customers use electricity at different times of the day, which imposes different costs throughout the day to the distribution system, and therefore, an efficient rate design should reflect this pattern (NECEC Brief at 9). According to NECEC, energy consumption during the time of the system peak causes higher distribution costs (NECEC Brief at 9, citing Exhs. AC-ML-1, at 26; CLC-JFW-1, at 16; SREF-TW/MW-1, at 7; VS-NP-1, at 32-33; SREF-TW/MW-1 (Supp.) at 14; SREF-TW/MW-1 (Surr.) at 10-12)). Thus, NECEC alleges that a rate design that charges customers a higher price for usage during peak periods creates a stronger link between the rate design and the distribution costs it is designed to recover, and further provides customers with an incentive to reduce their consumption and their own costs, which reduces system costs (NECEC Brief at 10, citing Exhs. SREF-TW/MW-1, at 7; SREF-TW/MW-1 (Supp.) at 35); NECEC Reply Brief at 3-4).

Further, NECEC argues that a TOU rate design structure improves the cost efficiency of the distribution system because it sends price signals to customers that reflect cost causation (NECEC Brief at 10, citing Exhs. AC-ML-1, at 27, 28; NECEC Reply Brief at 3-4). NECEC contends that Eversource's proposal to eliminate all of its optional TOU rates and to place these customers on rates that do not impose a peak period price signal, will weaken the link between its rate design and the costs to efficiently operate its distribution system (NECEC Brief at 10-11, citing Exhs. ES-RDP-1, at 16, 42-44, 53; ES-RDP-4, Sch. RDP-1). NECEC maintains that the Companies' one new TOU option for small commercial customers is insufficient because the price differential between the on- and off-peak periods is too small (NECEC Brief at 12, citing Exhs. AC-ML-1, at 31; ES-RDP-4 (East), Sch. RDP-3, at 3; ES-RDP-5, Sch. RDP-1, at 1). Thus, NECEC contends that the design of proposed Rate G-5 mutes its price signal (NECEC Brief at 12). Therefore, NECEC recommends that the Department direct Eversource to maintain its current TOU design or to allow gradual rate design changes that maintain the current price signals (NECEC Brief at 12).

Moreover, NECEC disputes Eversource's argument that TOU rates are not appropriate for distribution rates because the distribution system is built to recover the cost to meet the peak demand (NECEC Brief at 13, citing Exhs. ES-RDP-1, at 16; DPU-18-11).

According to NECEC, Eversource ignores the fact that customers can control their costs during peak periods if the rate design provides them the proper price signal (NECEC Brief at 13, citing Exhs. AC-ML-1, at 25, 29; SREF-TW/MW-1, at 32; CLC-JFW-1, at 14, 16; SREF-TW/MW-1 (Supp.) at 36). Further, NECEC asserts that low adoption of Eversource's current residential rates does not necessarily imply lack of interest from customers, but, instead, could reflect a lack of information or poor marketing (NECEC Brief at 13, citing Exhs. AC-ML-1, at 29; SREF-TW/MW-1 (Supp.) at 35). Moreover, NECEC argues that distribution and transmission costs, which have time varying bases, could be coordinated with TOU rates for energy rates proposed in D.P.U. 15-122 (NECEC Brief at 13, citing Exh. AC-ML-1, at 29-30).

Finally, NECEC alleges that Eversource's rate design proposal is not consistent with the Department's "vision for the future" (NECEC Brief at 13). According to NECEC, the Department set forth a plan for the utility industry future that will provide customers timely information about their electricity consumption and costs so that customers could respond by reducing or shifting consumption and reducing costs to all customers (NECEC Brief at 13-14, citing Modernization of the Electric Grid, D.P.U. 12-76-B at 1-2, 9 (2014); Time Varying Rates, D.P.U. 14-04-B at 1 (2014); D.P.U. 15-155 at 383, 384). Therefore, NECEC asserts that, although the Department is pursuing pricing options to provide price signals to customers regarding the link between consumption and distribution system costs, Eversource is eliminating rate design that can assist in achieving these goals (NECEC Brief at 14, citing

D.P.U. 15-120; D.P.U. 15-121; D.P.U. 15-122). For all these reasons, NECEC urges the Department to reject the Companies' proposal to eliminate TOU rates (NECEC Brief at 14).

iii. Companies

According to the Companies, residential TOU rates should not be implemented because they will conflict with time varying basic service rates, as directed by the Department in D.P.U. 14-04-B (Companies Brief at 45). The Companies maintain that distribution peaks for residential customers based on customer load profiles do not align with basic service peak periods, which are based on ISO-NE peaks reflecting market-based pricing (Companies Brief at 45-46).

Moreover, the Companies assert that many customers have not adopted existing residential TOU rates (Companies Brief at 46). According to Eversource, only 0.02 percent of residential customers take service on its TOU rates (Companies Brief at 46). The Companies argue that it would be difficult for residential customers to avoid peak period rates because residential customers do not have the ability to shift or reduce load (Companies Brief at 46).

In response to Acadia Center's argument that TOU rates should be redesigned to eliminate demand charges, the Companies disagree and maintain that peak period pricing should be based on demand because the distribution system is capacity based[53] (Companies Brief at 45; Companies Reply Brief at 32). The Companies assert that the volume of energy

53 The Companies maintain that capacity requirements at different points on the distribution system, such as the substation, circuit, and customer service point, guide distribution system planning (Companies Brief at 45; Companies Reply Brief at 32).

delivered in a peak or off-peak period has little bearing on distribution system planning (Companies Reply Brief at 32). According to the Companies, the volume of energy delivered in a peak period versus an off-peak period has little influence on system planning, and, therefore, Eversource asserts that TOU rates have no basis for distribution pricing (Companies Brief at 45). In addition, Eversource adds that various intervenors acknowledge that distribution system planning is based on capacity, and not energy, via their arguments on NCP demand rates for residential and small C&I customers (Companies Reply Brief at 32).

Finally, the Companies allege that the Department has signaled a departure from TOU distribution rates (Companies Brief at 45, citing D.P.U. 14-04-B at 14; Companies Reply Brief at 32). Therefore, the Companies allege that TOU rates are not more beneficial than demand charges for small C&I customers (Companies Reply Brief at 32).

c. Analysis and Findings

i. Peak Period Definition

As stated above, with the Department's directive that the Companies retain their legacy C&I rate classes at this time, this issue is moot. The Companies will not alter the TOU peak period in the instant case. Accordingly, the Department directs Eversource to continue to define the peak period as currently defined (see M.D.P.U. No. 1005W at 1; M.D.P.U. No. 1008W at 1; M.D.P.U. No. 1007W at 1; M.D.P.U. No. 1049B at 1; M.D.T.E. No. 132F at 2-3; M.D.T.E. No. 133F at 2; M.D.T.E. No. 134F at 3; M.D.T.E. No. 232G at 3; M.D.T.E. No. 233G at 2-3; M.D.T.E. No. 234G at 2-3;

M.D.T.E. No. 236G at 2-3; M.D.T.E. No. 331F at 3; M.D.T.E. No. 332F at 3; M.D.T.E. No. 336F at 5).

ii. Time of Use Rate Design

The Department has determined that the goals of designing utility rate structure are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 15-155, at 383. In order to achieve the rate structure goal of simplicity, the Companies proposed to consolidate and align their rate classes across the Eversource system to a single set of tariffs governing base distribution rates for both NSTAR Electric and WMECo (Exh. ES-RDP-1, at 8-9). In doing so, the Companies proposed to eliminate the following current residential rates: (1) Boston Edison Company Rate R-4 (M.D.T.E. No. 123F), Cambridge Electric Light Company Rate R-5 and Rate R-6 (M.D.P.U. No. 224; M.D.P.U. No. 225), and Commonwealth Electric Company Rate R-6 (M.D.P.U. No. 325). In Section IV.D.5.c.i & n.29 above, the Department allowed the Companies' proposal to eliminate their optional residential TOU rates in order to consolidate and align their residential rates and tariffs to better achieve the rate structure goal of simplicity. Further, there are very few customers who take service on these rates (Exh. DPU-15-1, Att. (a) at 3). Moreover, the Department has determined that there is not a sufficient cost basis to require time varying distribution rates. D.P.U. 14-04-B at 13-14. Accordingly, the Department allows the Companies' proposal to eliminate their optional, residential TOU distribution rates.

In Section IV.D.5.c.ii, the Department directed the Companies to retain their legacy C&I rate classes at this time. The Companies will not alter their TOU C&I rates in the instant case. Accordingly, the Department directs Eversource to continue to bill its C&I rates in accordance with the directives in this Order.

H. Reconciling Mechanisms

1. Transmission Service Cost Adjustment

a. Introduction

The Transmission Service Cost Adjustment ("TSCA") (proposed M.D.P.U. No. 518) recovers the charges that the Companies incur under their Federal Energy Regulatory Commission ("FERC") approved transmission tariffs (Exh. ES-RDP-14 (Part 4) at 259; RR-DPU-51, Att. (a) at 101). The Companies establish an annual TSCA factor based on a forecast of transmission costs and include a full reconciliation for any over- or under-recoveries occurring under the prior year's adjustment (Exh. ES-RDP-14 (Part 4) at 259; RR-DPU-51, Att. (a) at 101).

b. Companies Initial Proposal

In their initial filing, the Companies proposed to develop a separate transmission revenue requirement for NSTAR Electric and WMECo for both 2018 and 2019 (Tr. 16, at 3232). The Companies proposed to allocate their transmission revenue requirement to rate classes on the basis of the each rate class's average of its 12-month coincident peak ("12 CP") (i.e., the class contribution to the Companies' coincident system peak)

(Exh. ES-RDP-1, at 32; Tr. 16, at 3232).[54] The Companies performed this allocation separately for NSTAR Electric and WMECo rate classes, and then summed the results to create a class revenue target based on the proposed aligned rate classes (e.g., one transmission rate for both NSTAR Electric's and WMECo's proposed aligned Rate G-1, despite proposing separate distribution rates) (Tr. 16, at 3232).[55] Next, the Companies divided the allocated revenue requirement by either demand or energy to arrive at the applicable unit rate for each proposed aligned rate class (Exh. ES-RDP-1, at 31-32).[56] Eversource proposed to bill the transmission rate as an energy charge (per kWh) for residential customers and as a demand charge (per kW) for C&I customers (Exh. ES-RDP-1, at 32). The Companies proposed to apply the demand charges to the entire demand that a C&I customer registers (Exh. ES-RDP-1, at 32).

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[54] The Companies currently employ this method in their WMECo service territory (Exh. ES-RDP-1, at 32). For NSTAR Electric, current transmission rates are calculated based on legacy allocations for Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company (Tr. 16, at 3239). Every year in NSTAR Electric's annual TSCA filing, the company calculates the average transmission rate for NSTAR Electric (Tr. 16, at 3239). NSTAR Electric then increases the transmission rates for each legacy company by the same percentage as the overall NSTAR Electric increase in order to reach the average NSTAR Electric transmission rate (Tr. 16, at 3239). Thus, NSTAR Electric's current method has preserved transmission rate design based on the legacy rate class allocation, which was established during electric industry restructuring (Tr. 16, at 3239).

[55] Eversource proposed separate transmission rates for NSTAR Electric and WMECo to be effective in 2018 (Tr. 16, at 3231).

[56] Aligned rates classes refer to the standardized availability and applicability provisions for each rate class or tariff so that customers in Eastern Massachusetts and Western Massachusetts will be subject to a single set of rules (Exh. ES-RDP-1, at 8).

c. Companies Revised Proposal

The Companies proposed to change the allocation method for transmission rates in their revised rate design proposal (Exh. DPU-56-9, at 1, 5 (Supp.); Tr. 16, at 3231). For transmission rates in both 2018 and 2019, Eversource proposed to allocate transmission costs on the basis of the 12 CP for each rate class using the total transmission revenue requirement for both NSTAR Electric and WMECo (Exhs. DPU-56-9, at 1,5 (Supp.); DPU-63-15; Tr. 16, at 3232).

The Companies proposed to allocate the 2018 transmission revenue requirement on the basis of the 12 CP for each legacy rate class (Exhs. ES-RDP-8 (ALT1), WP RDP-11 (East); DPU-63-15). Eversource designed transmission rates based on the legacy rate design (Exh. DPU-63-15). For example, if the customer's legacy rate design was neither a straight per-kWh rate nor per-kW demand rate, then it was converted to the existing legacy rate design (Exhs. ES-RDP-8 (ALT1), WP RDP-13 (East); DPU-63-15).

During the proceeding, the Companies proposed to further modify the revised transmission allocation and revised rate design proposal, with an additional modification of the transmission revenue requirement allocation to Commonwealth Electric Company's legacy Rates G-7 and G-7S (Exhs. DPU-63-13; CLC-7-2 & Atts.).[57] In the June 1, 2017 revised rate design proposal, Eversource consolidated legacy Rate G-1 and Rate G-7/Rate G-7S for

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57 Commonwealth Electric Company's Rate G-7 is an optional C&I TOU rate, and Rate G-7S is an optional seasonal rate class for customers that would otherwise qualify for service on Rate G-7 (M.D.T.E. No. 336F; see also RR-DPU-51, Att. (a) at 514-518).

the purposes of allocating transmission costs, and the resulting rate design caused bill impacts of more than ten percent to some large low-load factor customers on Commonwealth Electric Company's legacy Rate G-7 (Exhs. ES-RDP-3 (ALT1), Sch. RDP-3 (East); CLC-7-2). The Companies stated that these bill impacts were an unintended consequence of allocating transmission costs to the rate class groupings used in the legacy cost of service (Exh. CLC-7-2). Therefore, the Companies proposed a further revision to separately allocate transmission costs to Rate G-7 and Rate G-7S to lower bill impacts for customers in these rate classes (Exh. CLC-7-2 & Atts. (a), (b)).

For 2019, the Companies proposed consolidated transmission rates for residential customers, but separate transmission rates for C&I customers in NSTAR Electric and WMECo by determining rate class cost responsibility using the 12 CP allocations to the separate, aligned rate classes (Exh. DPU-56-9, at 5 (Supp.)). Further, Eversource proposed to modify the structure of transmission rates for small C&I customers in its revised rate design proposal (Exh. DPU-56-9, at 5 (Supp.)). Eversource proposed to bill small C&I customers on a per-kWh charge for the first block (rather than a demand charge in the first block) (Exh. DPU-56-9, at 5 (Supp.)).[58]

Moreover, the Companies propose to transfer the majority of WMECo's legacy Rate T-5 customers to aligned Rate G-4 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (West)). Eversource propose to continue to offer WMECo's legacy Rate T-5

58 Depending on the rate class, a certain threshold of demand will be exempt from transmission billing and the customer will pay on a per-kWh basis instead (Exh. DPU-56-9, at 6 (Supp.)).

customers a transmission rate that recovers transmission costs on the basis of a customer's coincident peak demand (Exh. DPU-12-1). However, the Companies propose that any new customers taking service under proposed aligned Rate G-4 will be billed on the basis of demand as measured during on-peak hours (Exh. DPU-12-1). Therefore, the Companies will not extend the coincident peak billing method for transmission rates to new customers or existing customers other than legacy Rate T-5 customers (Exh. DPU-12-1).

The table below shows the Companies' initial and revised transmission rate design proposals for 2019 based on the revenue requirement as initially filed (Exh. DPU-56-9, at 6 (Supp.)).

Proposed Rate Class	Initial	Revised	$Change	%Change
R-1/R-2 EMA/WMA All kWh	$0.02556	$0.02635	$0.00079	3.1%
R-3/R-4 EMA/WMA All kWh	$0.02533	$0.02610	$0.00077	3.0%
G-1ND EMA All kWh	$0.02261	$0.02230	-$0.00031	-1.4%
G-1ND WMA All kWh	$0.02261	$0.02328	$0.00067	3.0%
G-1D EMA Energy – All kWh Demand – Block 1 Demand – Block 2	 $0.00000 $6.26 $6.26	 $0.01032 $0.00 $6.27	 $0.01032 -$6.26 $0.01	 N/A -100.0% 0.2%
G-1D WMA Energy – All kWh Demand – Block 1 Demand – Block 2	 $0.00000 $6.26 $6.26	 $0.00344 $0.00 $5.94	 $0.00344 -$6.26 -$0.32	 N/A -100.0% -5.2%
G-2 EMA Energy – Peak Energy – Off Peak Demand – Block 1 Demand – Block 2 Demand – Block 3	 $0.00000 $0.00000 $8.43 $8.43 $8.43	 $0.00145 $0.00145 $0.00 $8.37 $8.37	 $0.00145 $0.00145 -$8.43 -$0.06 -$0.06	 N/A N/A -100.0% -0.8% -0.8%
G-2 WMA Demand – All kW	 $8.43	 $7.12	 -$1.32	 -15.6%
G-3 EMA Demand – All kW	 $9.12	 $8.98	 -$0.14	 -1.5%
G-3 WMA Demand – All kW	 $9.12	 $8.25	 -$0.87	 -9.5%
G-4 EMA All kW	 $8.83	 $9.10	 $0.26	 3.0%
G-4 WMA All kW	 $8.83	 $7.59	 -$1.25	 -14.1%

d. Positions of the Parties

i. Acadia Center

Acadia Center recommends that the Department approve the Companies' revised transmission allocation proposal that consolidates the transmission revenue requirement but separates transmission rates for NSTAR Electric and WMECo C&I customers (Acadia Center Brief at 8-9, citing Tr. 16, at 3235). According to Acadia Center, the revised transmission rate design proposal improves the Companies' initial proposal because C&I customers should pay for the transmission costs that they incur (Acadia Center Brief at 9). Therefore, Acadia Center recommends that the Department reject the Companies' initial proposal to consolidate C&I transmission rates (Acadia Center Brief at 22; Acadia Center Reply Brief at 2, 9).

ii. Cape Light Compact

According to Cape Light Compact, the Companies' initial transmission rate design proposal shifts $23 million in transmission costs from NSTAR Electric non-residential customers to NSTAR Electric residential and WMECo non-residential customers (Cape Light Compact Brief at 24-25, citing Exh. CLC-JFW-Supplemental-1, at 17). In particular, Cape Light Compact asserts that $14.4 million is shifted to NSTAR Electric residential customers (Cape Light Compact Brief at 25, citing Exh. CLC-JFW-Supplemental-1, at 17). Further, Cape Light Compact argues that the Companies' revised rate design proposal shifts an additional $5.1 million in transmission costs to NSTAR Electric residential customers (Cape Light Compact Brief at 25). Cape Light Compact concludes that these cost shifts under the revised rate design proposal are unjustified (Cape Light Compact Brief at 25). Moreover, Cape Light Compact maintains that the Companies' proposal is arbitrary because they did not justify the transmission cost shift using a cost of service study (Cape Light Compact Brief at 25, 27). Moreover, Cape Light Compact alleges that Eversource's proposal results in the unintended consequences of significant bill impacts to legacy Commonwealth Electric Company Rate G-7 and G-7S (Cape Light Compact Brief at 25, 27 citing Exh. CLC-7-2).

Cape Light Compact further argues that in Eversource's initial proposal, it justified a consolidated transmission cost revenue requirement on the basis that after FERC approved the NSTAR Electric and WMECo merger, Eversource would operate under one transmission tariff (Cape Light Compact Brief at 26, citing Exh. ES-RDP-1, at 31). According to Cape Light Compact, however, the Companies' revised rate design proposal deviates from this justification by separating the non-residential rate classes to allocate transmission costs (Cape Light Compact Brief at 26, citing Exh. DPU-56-9, at 5 (Supp.)). Therefore, Cape Light Compact alleges that the Companies intended to reduce WMECo C&I bill impacts by re-allocating the transmission costs in the revised rate design proposal (Cape Light Compact Brief at 26). Cape Light Compact maintains that all rate classes should be consolidated for the purposes of allocating the consolidated transmission revenue requirement according to the Companies' initial rate design proposal (Cape Light Compact Brief at 12, 26, 27, 28, 80 citing Exh. CLC-JFW-Supplemental-1, at 22).

Cape Light Compact asserts that the Department should deny the Companies' revised rate design proposal because it arbitrarily shifts $5.1 million in transmission costs onto residential customers (Cape Light Compact Brief at 27-28). However, Cape Light Compact argues that if the Department allows the Companies' revised rate design proposal, the Department should approve the modification Eversource offered to separately allocate transmission costs to Rate G-7 and Rate G-7S to lower bill impacts (Cape Light Compact Brief at 27, 28, 80 citing Exhs. CLC-7-2; DPU-63-13).

Moreover, Cape Light Compact opposes the Companies' initial transmission rate structure proposal because it includes a demand charge for Commonwealth Electric Company customers on legacy Rate G-1 (Cape Light Compact Brief at 71-72). According to Cape Light Compact, billing small C&I customers for transmission service though a demand charge calculated using the class contribution to the Companies' coincident peak is inconsistent with the rate design goal of fairness because Commonwealth Electric experiences a non-coincident peak (Cape Light Compact Brief at 72 n.35, citing Exh. CLC-KFG-1, at 15). Therefore, Cape Light Compact argues that it is not fair to bill customers for transmission costs that are not reflective of their contribution to such costs (Cape Light Compact Brief at 72 n.35, citing Exh. CLC-KFG-1, at 15). Accordingly, Cape Light Compact recommends that the Department reject these rate design changes (Cape Light Compact Brief at 72).

iii. FEA

FEA argues that if the Department approves the NSTAR Electric and WMECo merger, then ISO-New England ("ISO-NE") will bill Eversource for transmission service based on the 12 CP of the combined Eversource utility (FEA Brief at 11). If this combined billing occurs, then FEA supports the Companies' initial proposal regarding transmission revenue allocation (FEA Brief at 11). Further, FEA maintains that the Companies' initial and revised transmission rate design proposals are reasonable (FEA Brief at 11).

iv. TEC

(A) Allocation and Design

TEC recommends that the Department approve the Companies' revised transmission rate proposal that provides separate rates for NSTAR Electric and WMECo customers (TEC Brief at 5, 20, 24). According to TEC, NSTAR Electric and WMECo have different load characteristics and peak at different times (TEC Brief at 20). Therefore, TEC alleges that the proposed revised transmission rate design avoids cross subsidies (TEC Brief at 5, 20).

(B) Availability

TEC recommends that the Department allow Eversource to offer the coincident peak transmission billing to large customers in the NSTAR Electric service territory, such as those customers with cogeneration, energy storage, or other means of shifting load during peak periods (TEC Brief at 16, 19). TEC maintains that offering the coincident peak transmission billing option to NSTAR Electric customers is consistent with the Department's rate design goals of fairness, efficiency, and cost-causation (TEC Brief at 17-18; TEC Reply Brief at 4). In particular, TEC contends this billing option is efficient because it links the customer's contribution to the monthly transmission peak, and fair because it will reduce rate shock to certain customers (TEC Brief at 17-18). Moreover, TEC maintains that the Department stated that coincident peak billing removes cross-subsidization of transmission costs within rate classes by assigning more cost responsibility to those customers whose peak demand that occurs on-peak versus off-peak (TEC Brief at 15, citing D.P.U. 10-70, Optional Interval Metered Transmission Pricing Report (November 22, 2011)).[59] Further, TEC contends that allowing current standby rate customers to take the coincident peak transmission billing option may help mitigate any rate shock these customers may experience when standby rates are eliminated and this option will reduce overall transmission demands for Eversource (TEC Brief at 17, citing Tr. 17, at 3425).[60] Therefore, TEC maintains that coincident peak transmission billing is a reasonable application of ratemaking principles (TEC Reply Brief at 4).

According to TEC, coincident peak billing for transmission is beneficial to all customers because it can lead to a reduction in transmission demand which reduces transmission cost allocation to the utility, and, in the long run, may defer future transmission investments in the ISO-NE region (TEC Brief at 14, 16 citing Tr. 16, at 3401-3403; TEC Reply Brief at 6). Further, TEC alleges that coincident peak billing for transmission service creates incentives for certain customers to reduce consumption during periods of high monthly demand, thereby achieving savings by avoiding demand at the time of system peak

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59 In addition, TEC claims that the Department estimated that 12 CP transmission billing for some rate classes provides a more equitable assignment of cost responsibility compared to billing for transmission costs using a customer's peak demand, which may not coincide with system peak demand (TEC Brief at 16, citing D.P.U. Western Massachusetts Electric Company, 10-70-B at 6 (2012)).

60 According to TEC, the current standby rate is significantly discounted from the current regular distribution rate (TEC Brief at 17, citing Tr. 17, at 3425).

and thus encouraging investment in cogeneration, which provides demand-related benefits (TEC Brief at 14, 15, citing D.P.U. 10-70, Optional Interval Metered Transmission Pricing Report (November 22, 2011); TEC Reply Brief at 6, citing NECEC Brief at 12). Moreover, TEC contends that the Department recognized possible distribution system benefits from the use of coincident peak billing by reducing congestion during peak hours, lowering locational marginal prices, and creating flatter load profiles (TEC Brief at 15-16, citing Western Massachusetts Electric Company, D.P.U. 10-70-B (2012)). Therefore, TEC maintains that the Department should consider these demand-related benefits when considering expanding coincident peak transmission billing (TEC Reply Brief at 6).

Further, TEC disagrees with the Companies' characterization that coincident peak transmission billing is inequitable because it favors some customers over other customers (TEC Reply Brief at 3, citing Companies Brief at 46). According to TEC, the type of "inequity" that the Companies describe is inherent at the beginning stages in every incentive mechanism (TEC Reply Brief at 3). TEC explains that incentives are intended to treat the desired behavior more favorably than other behaviors thereby creating an "inequity" (TEC Reply Brief at 3). However, TEC maintains that this "inequity" causes customers to modify their behavior in order to achieve the desired outcome (TEC Reply Brief at 3). Moreover, TEC argues that the Department previously determined that coincident peak transmission billing is "equitable" (TEC Reply Brief at 5-6, citing D.P.U. 10-70-B at 6). In addition, TEC argues that the existing transmission rate design undervalues customer investments (TEC Reply Brief at 6). TEC concludes that incentive mechanisms, such as the coincident peak transmission billing, are valuable tools in ratemaking and public policy (TEC Reply Brief at 4).

Moreover, TEC contends that Eversource did not propose to expand coincident peak transmission billing to Eversource contending that it is administratively burdensome (TEC Brief at 18). TEC argues that the administrative burden of offering coincident peak transmission billing is outweighed by the benefits that it provides to customers and the distribution system (TEC Brief at 18-19, 20). In addition, TEC notes that the Companies are administratively capable of processing the current coincident peak transmission billing for WMECo's legacy Rate T-5 customers as well as for thousands of net metering requests (TEC Brief at 19-20). Therefore, TEC asserts that the Companies' objections to expanding coincident peak transmission billing lack merit (TEC Brief at 20).

In response to the Companies' argument that customers are unable to respond to the coincident peak transmission billing price signal because system peak is not known until the end of the billing period, TEC maintains that the Department already considered and rejected this argument, finding that there is "sufficient publicly available information available to allow customers to make reasonable inferences as to when the system peaks might occur" (TEC Brief at 7, citing D.P.U. 10-70-B at 6). For all these reasons, TEC recommends that coincident peak transmission billing be available on an optional basis to large customers in both NSTAR Electric and WMECo service territories (TEC Brief at 20; TEC Reply Brief at 2).

v. UMass

According to UMass, the Companies allocate transmission costs to large WMECo C&I customers based on coincident peak demand and to large NSTAR Electric C&I customers based on non-coincident peak demand (UMass Brief at 5, 8). UMass asserts that such treatment results in NSTAR Electric customers receiving higher allocation of transmission costs without the ability to reduce their electric bills (UMass Brief at 5). UMass alleges that it is not just, reasonable, fair, or equitable for Eversource to provide similar customers within its service territory different rate treatment (UMass Brief at 6).

Further, UMass maintains that it is fair, reasonable, and efficient to bill large C&I customers for transmission costs in the same manner that ISO-NE allocates and bills regional transmission costs to Eversource, and to align transmission costs with transmission rates (UMass Brief at 8; UMass Reply Brief at 3). Therefore, UMass supports the allocation of transmission costs based on coincident peak because it is based on cost-causation principles, that is, customers are charged based on the costs that the Companies incur to serve them (UMass Reply Brief at 3).

UMass disagrees with what it claims is the Companies' assertion that UMass's proposal results in discriminatory treatment of similar customers (UMass Reply Brief at 4-6). UMass maintains that the Department's rate design rules do not prohibit a rate design that causes some customers to pay more and others to pay less (UMass Reply Brief at 2). According to UMass, large energy users and organizations that represent them support coincident peak transmission billing (UMass Reply Brief at 5). Moreover, UMass contends that Eversource's claims are incorrect that customers cannot respond to coincident peak billing and that only customers with cogeneration or storage can reduce coincident peak demand (UMass Reply Brief at 5-6). For example, UMass asserts that 40 percent of WMECo's largest customers have successfully responded to the coincident peak billing price signal to reduce their bills (UMass Reply Brief at 6). Further, UMass maintains that energy efficiency measures also may reduce a customer's peak demand (UMass Reply Brief at 6).

According to UMass, all customers benefit when any Eversource customer reduces the Companies' peak demand by offsetting transmission investments or reducing the allocation of regional transmission costs (UMass Brief at 7-8; UMass Reply Brief at 3). For example, UMass claims that WMECo customers are incentivized to reduce their coincident peak to reduce their own costs, which thereby reduces the regional costs allocated to Eversource (UMass Brief at 8). UMass maintains that billing NSTAR Electric customers for transmission costs based on coincident peak will create the same incentive for additional customers to reduce their peak demands and regional costs allocated to Eversource (UMass Brief at 9).

UMass further contends that extending coincident peak transmission billing to large NSTAR Electric customers may result in more customer installations of DERs and energy storage facilities to reduce their peak demands (UMass Reply Brief at 8-9). UMass claims that this result is consistent with the Commonwealth's public policies to improve air quality, reduce greenhouse gas emissions, increase reliance on renewable resources, and expand the deployment of energy efficiency (UMass Reply Brief at 8-9, citing Executive Order 484;

Massachusetts Clean Energy and Climate Plan for 2020 (December 29, 2010); An Act Relative to Green Communities, St. 2008, c. 169; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298, codified as G.L. c. 21N, § 3; An Act Relative to Solar Energy, St. 2016, c. 75). For these reasons, UMass contends that Eversource should offer coincident peak transmission billing to large customers in the NSTAR Electric service territory (UMass Brief at 6, 9-10; UMass Reply Brief at 1, 4, 8).

vi. WMIG

According to WMIG, coincident peak billing for Rate T-5 customers is beneficial because it sends a price signal to reduce demand on the system and yields utility-wide benefits for all customers (WMIG Brief at 4, 9-10).[61] WMIG maintains that if the Companies' peak goes down, then the Companies' allocation of transmission costs goes down (WMIG Brief at 10, citing Tr. 16, at 3403). Therefore, WMIG maintains that a reduction in the allocation of transmission costs to the Companies benefits all of the Companies' customers (WMIG Brief at 10, citing Tr. 16, at 3403). Thus, WMIG recommends that the Department approve the continuation of Rate T-5 coincident peak transmission billing (WMIG Brief at 4, 10). Additionally, WMIG supports the expansion of coincident peak transmission billing to large NSTAR Electric customers (WMIG Brief at 10, n.26).

Further, WMIG argues that the Department should accept the Companies' proposal to maintain separate transmission rates so that they reflect geographical and transmission

61 WMIG asserts that many large customers have shifted their demand to reduce their transmission costs (WMIG Brief at 10).

demand differences between Eversource's customers in its respective service territories (WMIG Brief at 4, 10, citing Exh. DPU-56-9 (Supp.)). According to WMIG, separate transmission rates reflect the characteristics (economic, customers, peaks) of each service territory and accurately allocate transmission costs (WMIG Brief at 10-11).

vii. Companies

Eversource argues that TEC's proposal to expand coincident peak transmission billing to large C&I customers in NSTAR Electric's service territory on an opt-in basis is inequitable, and results in price discrimination (Companies Brief at 46; Companies Reply Brief at 28). According to the Companies, designing an opt-in rate available only to customers with cogeneration or storage would spread transmission costs to all customers in the rate class based on coincident peak demand, but would apply the rate only to customers that can reduce demand at the time of system peak (Companies Brief at 46; Companies Reply Brief at 28). The Companies argue that the rate would be underpriced because not all customers would elect the rate, and would create shortfall of cost recovery (Companies Reply Brief at 28). Therefore, the Companies maintain that such rate design is discriminatory because it allows a subset of customers to take service on a lower cost rate than the rate available to other customers in the same rate class (Companies Brief at 46; Companies Reply Brief at 28).

Further, Eversource contends that UMass's proposal to expand the coincident peak transmission billing to all customers in proposed Rate G-4 is inappropriate (Companies Brief at 46). The Companies maintain that coincident peak transmission billing does not allow for customers to respond to a price signal because system peak is not known until the end of a billing period (Companies Brief at 46-47). Further, the Companies allege that ISO-NE provides information pertaining to the ISO-NE system peak, not the Northeast Utilities system peak,[62] and therefore, information is not readily available to customers to make decisions (Companies Reply Brief at 27-28, citing D.P.U. 10-70-B).

Additionally, the Companies assert that coincident peak transmission billing in WMECo resulted in cost increases to smaller customers that are unable to respond to the price signal and shift usage outside the coincident peak period to reduce charges (Companies Brief at 47, citing Exh. DPU-12-1; Companies Reply Brief at 36, citing Tr. 16, at 3397). Further, Eversource alleges that coincident peak transmission billing results in intra-class inequities (Companies Reply Brief at 36). The Companies argue that in the four years that coincident peak transmission billing has been available to Rate T-5 customers, the number of customers benefitting from it has not improved (Companies Reply Brief at 28, 36, citing Exh. DPU-12-1, Att.). Eversource claims that because 60 percent of Rate T-5 customers do not benefit from the rate design, it is not supported by all Rate T-5 customers (Companies Reply Brief at 35, citing Exh. DPU-12-1). Further, the Companies maintain that implementing coincident peak transmission billing for NSTAR Electric could result in the cost shifting to other electric utilities within the ISO-NE region due to the large customer base (Companies Reply Brief at 28, citing D.P.U. 10-170-B). Therefore, the Companies

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[62] ISO-NE considers Northeast Utilities to comprise WMECo and its affiliates The Connecticut Light and Power Company and Public Service Company of New Hampshire.

argue that, for continuity reasons, they have proposed to continue billing coincident peak transmission for large C&I customers in WMECo, but do not propose any further expansion of this billing option (Companies Brief at 47).

Finally, the Companies assert that their proposed transmission rate design is consistent with the Department's rate design principles (Companies Reply Brief at 36). Eversource explains that it allocates transmission costs on the basis of coincident peak demand but collects these costs from individual customers on the basis of individual customer demand (Companies Reply Brief at 36, citing Exh. ES-RDP-1, at 32). The Companies maintain that this method is consistent with the method that other distribution companies in the Commonwealth use for transmission cost allocation and rate design (Companies Reply Brief at 36). According to the Companies, billing customers for transmission costs on the basis of individual demand does not prevent these customers from investing in cogeneration (Companies Reply Brief at 36-37). Moreover, Eversource explains that legacy Rate T-5 customers are allocated transmission costs on the basis of their contribution to the transmission system peak and billed transmission costs based on their demand at the time of the Northeast Utilities system peak (Companies Reply Brief at 36). Therefore, the Companies maintain that they incentivize legacy Rate T-5 customers to reduce their demand (Companies Reply Brief at 36).

e. Analysis and Findings

In WMECo's last rate case, the Department approved the use of the 12 CP allocation method for the allocation of transmission costs and determined it to be reasonable.

D.P.U. 10-70, at 337. The Department directed WMECo to update the 12 CP allocators on an annual basis in its transmission reconciliation filing. D.P.U. 10-70, at 338. The Department finds it reasonable to extend the use of the 12 CP allocation method for the allocation of transmission costs to NSTAR Electric customers because this allocation method sends a more accurate price signal to customers regarding the true cost of transmission service and is consistent with how FERC designs transmission rates, under which NSTAR Electric receives transmission service. D.P.U. 10-70, at 337.

In the D.P.U. 17-05 Order, the Department allowed the corporate consolidation and merger NSTAR Electric and WMECo into NSTAR Electric Company. D.P.U. 17-05, at 43-44.[63] Therefore, Eversource will operate under one transmission tariff. Accordingly, the Department approves Eversource's proposal to consolidate the transmission revenue requirement prior to allocating these costs to rate classes.

In Sections IV.D.5.c.i and ii above, the Department approved the Companies' residential rate consolidation proposal, but the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time. Thus, the Department directs Eversource to allocate transmission costs to the approved residential and C&I rate classes accordingly. Moreover, Cape Light Compact's opposition to the Companies' proposed demand charge for Commonwealth Electric Company customers on legacy Rate G-1 is

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63 FERC has approved the internal corporate reorganization of NSTAR Electric and WMECo, and it has approved NSTAR Electric's acquisition of WMECo's jurisdictional facilities (Exhs. ES-DPH-1, at 4: DPU-20-1, at 2-3;). D.P.U. 17-05, at 31.

rendered moot because the Companies will retain the existing transmission rate structure at this time (see Section IV.D.5.c.ii above).[64] Further, the Department approves Eversource's proposed modification to separately allocate transmission costs to Rate G-7 and Rate G-7S (Exhs. CLC-7-2; DPU-63-13).

Regarding the expansion of coincident peak transmission billing currently offered to legacy Rate T-5 customers to NSTAR Electric customers, the Department recognizes that pricing transmission service based on a customer's consumption at the time of system peak rather than based on the customer's peak, which may not coincide with the system peak, provides a more equitable assignment of cost responsibility. D.P.U. 10-70-B at 6. TEC recommends extending this transmission rate offering on an opt-in basis to large NSTAR Electric C&I customers (TEC Brief at 20; TEC Reply Brief at 2). The coincident peak transmission rate cannot be implemented on an opt-in basis because only those customers who would experience lower transmission costs would elect the alternate rate. The remaining customers would continue on the existing transmission rate. Consequently, Eversource would presumably collect the under-recovery of transmission costs caused by these customers from other customers.

Given that the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time, it is likely that, fairness to all NSTAR Electric customers would lead to three separate offerings of coincident peak transmission billing for

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64 Eversource bills Commonwealth Electric Company G-1 customers for transmission service using a per-kWh rate (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3 (East) at 32-33).

customers in the three legacy service areas. This would result in additional administrative burden and customer confusion. Moreover, there is not sufficient evidence to evaluate bill impacts to NSTAR Electric customers that would be subject to a mandatory coincident peak transmission rate. As a result, the Department declines to adopt the recommendation to expand coincident peak transmission billing to large NSTAR Electric customers at this time. The Department encourages the Companies to evaluate further the expansion of coincident peak transmission billing to NSTAR Electric customers.

Finally, the Department has reviewed the Companies' proposed changes to its TSCA tariff (see Exh. ES-RDP-14 (Part 4) at 259). The Companies' TSCA tariff has not changed since 1998 (see Exh. ES-RDP-14 (Part 4) at 259). The Companies' proposed changes to the language in the TSCA, updating the tariff to use the appropriate terms (e.g., update references from "Department of Telecommunications and Energy" to "Department of Public Utilities"). Therefore, we find that the Companies' proposed changes to the TSCA tariff are reasonable and, therefore, we approve the proposed changes. Accordingly, the Department directs Eversource to file a revised TSCA tariff with its compliance filing consistent with the directives in this Order.

2. Net Metering Recovery Surcharge

a. Introduction

Eversource proposed to adopt a single Net Metering Tariff effective January 1, 2018 (proposed M.D.P.U. No. 527) (RR-DPU-51, Att. (a) at 292-317). Effective January 1, 2018, Eversource proposed to calculate the NMRS separately for NSTAR Electric customers and WMECo customers (RR-DPU-51, Att. (a) at 308-309). Effective January 1, 2019, Eversource proposed to combine the NMRS revenue requirement for both service areas and to calculate one NMRS (RR-DPU-51, Att. (a) at 309).

The Companies' proposed NMRS recovers, among other things, the cost of net metering credits provided to customers who qualify to participate under the Net Metering Tariff and the DDR associated with these customers' self-generation installed in accordance with G.L. c. 164, §§ 138 and 139 (RR-DPU-51, Att. (a) at 306-308). As noted, in their initial rate design proposal, the Companies proposed to maintain a separate NMRS between NSTAR Electric and WMECo (Exh. ES-RDP-1, at 28). The Companies proposed to consolidate the NMRS revenue requirement in their revised rate design proposal, and to allocate it to all rate classes using the base distribution revenue allocator beginning January 1, 2019 (RR-DPU-51, at 309).

Currently, NSTAR Electric and WMECo use different accounting methods to determine the NMRS revenue requirement (Exhs. DPU-18-16, at 2; DPU-30-3, Att.). Because NSTAR Electric's revenues were not decoupled prior to the Department's approval in this case, NSTAR Electric currently estimates its DDR and recovers it through the NMRS (Exh. DPU-18-16, at 2).[65] Further, the Companies stated that NSTAR Electric's accounting method recognizes net metering credits over a billing period based on netted kWhs (Exhs. DPU-18-16, at 2; DPU-30-3, Att.).

65 Currently, the Net Metering Tariffs allow the Companies' the option to recover DDR through either a RDM or the NMRS (M.D.P.U. No. 163D, § 1.08; M.D.P.U. No. 1048G, § 1.08).

Eversource explained that WMECo's metering and accounting methods allow it to recover WMECo's DDR through both its revenue decoupling mechanism ("RDM") and its NMRS (Exhs. DPU-18-16, at 2; DPU-30-3, Att.). Further, the Companies installed two channel revenue meters for WMECo's net metering customers, which allows for the registration of both exported and delivered kWh over a billing period (Exhs. DPU-18-16, at 2; DPU-30-3, Att.). Therefore, before netting the two kWh values associated with net metering, WMECo calculates net metering credits separately on the export and import channels by: (1) multiplying the net metering credit rate by the total kWh measured on the export channel; and (2) multiplying total delivery charges by the total kWh measured on the import channel (Exhs. DPU-18-16, at 2; DPU-30-3, Att.). In other words, where NSTAR Electric nets the billing period kWh and then multiplies the net kWh amount by the net metering credit rate to determine total net metering credits, WMECo nets the gross billing period credits and charges (Exhs. DPU-18-16, at 2; DPU-30-3, Att.).

The Companies state that under either method, the customer receives the same net metering credit on his or her bill, but the accounting and recovery mechanisms are not the same between WMECo and NSTAR Electric (Exhs. DPU-18-16, at 2; DPU-30-3, Att.). However, WMECo recognizes revenue associated with the total delivery charges that it calculates on the import channel, which includes revenue that actually has been displaced (Exhs. DPU-18-16, at 2; DPU-30-3, Att.). With this accounting, WMECo recovers a portion of DDR through the NMRS because the gross value of net metering credits (i.e., the net metering credit rate multiplied by the total kWh measured on the export channel, which is not equal to the value of net metering credits paid to customers as it appears on their bills) are included in the NMRS calculation of revenue requirement for recovery through the NMRS factors (Exhs. DPU-18-16, at 2; DPU-30-3, Att.). Eversource states that it recovers in its RDM any DDR not accounted for through WMECo's NMRS (Exhs. DPU-18-16, at 2; DPU-30-3, Att.). No parties addressed these issues on brief.

b. Analysis and Findings

The Department approved the Companies' RDM proposal in Section IV.H.3 below. Therefore, both Companies will operate under an RDM going forward. The Companies stated that they will:

> conform the separate accounting methods utilized currently by WMECo and NSTAR [Electric] for net metering to a single, uniform methodology. The Compan[ies] would modify the reporting currently applied by WMECo in its billing and accounting processes in order to be consistent with the current NSTAR [Electric] methodology for recovering net metering credits through the NMRS. DDR would no longer be calculated for recovery through the NMRS, but would be recovered through the Compan[ies]' proposed revenue decoupling mechanism
>
> (Exh. DPU-63-11).

The Companies stated that this modification requires minimal information technology costs to facilitate conformation of both reporting and accounting procedures (Exhs. DPU-56-2; DPU-63-12). Further, Eversource explained that test year billing determinants for WMECo would need to be lowered by 13,780,890 kWh to implement this change (Exh. DPU-65-1).[66]

[66] In implementing this change, the Department reduced WMECo's test year distribution revenue by $464,646 and increased the normalizing adjustment for revenue decoupling by $464,646. D.P.U. 17-05, at 72.

Therefore, the Department directs the Companies to implement their agreed-to modifications to the NMRS as described above.

Moreover, the Companies stated that they preferred the existing language in the Net Metering Tariff at Section 1.08 because current metering and accounting policies impact Eversource's recovery of DDR (Exh. DPU-18-16, at 1). Section 1.08 of the Net Metering Tariffs states, in part:

> If the Distribution Company operates under a revenue decoupling mechanism, the Distribution Company may elect to recover some or all of the charges listed below through a revenue decoupling mechanism or applicable reconciling mechanisms, as appropriate, rather than through an NMRS. If the Distribution Company elects not to file an NMRS, the Distribution Company must file a net metering report in lieu of the NMRS. The net metering report shall be in a form approved by the Department. The net metering report is for informational purposes only.
>
> M.D.P.U. No. 163D, § 1.08; M.D.P.U. No. 1048G, § 1.08.

During the course of the proceedings, the Department put forth modified language:

> If the Distribution Company operates under a revenue decoupling mechanism, the Distribution Company will recover the non-reconciling distribution portion of revenue displaced ("DDR") through a revenue decoupling mechanism and all other charges listed below through the operation of the NMRS. If the Distribution Company does not operate under a revenue decoupling mechanism, then the Distribution Company will recover the DDR and all other charges listed below through the operation of the NMRS.
>
> (Exh. DPU-18-16).

The Companies contend that under the Department's language, distribution companies with RDMs would be required to recover the non-reconciling portion of DDR only through the revenue decoupling adjustment (Exh. DPU-18-16).

As discussed above, the Companies agreed to modify their current metering and accounting policies to make them consistent across NSTAR Electric and WMECo (Exh. DPU-63-11). After the Companies implement this change, and because the Department allowed NSTAR Electric to implement a decoupling mechanism, NSTAR Electric will no longer calculate DDR for recovery through the NMRS, but, instead, Eversource will recover all DDR through its RDM (Exh. DPU-63-11). Accordingly, the Department directs the Companies to include the Department's modified language in their Net Metering Tariff at Section 1.08 which requires recovery of the "non-reconciling distribution portion of revenue displaced ("DDR") through a revenue decoupling mechanism and all other charges listed below through the operation of the NMRS" (Exh. DPU-18-16). Further, the Department expects that each electric distribution company will make the same modification to its Net Metering Tariff in the earlier of its next base distribution rate case filing or any other filing in which the Net Metering Provision is under review.

The Department has reviewed the Companies' proposal and is satisfied with the Companies' plan to implement one net metering tariff (proposed M.D.P.U. No. 527), subject to the modifications discussed above and in Section IV.E.4.g. Further, the Department allows the combination of the NMRS revenue requirement between NSTAR Electric and WMECo.

3. Revenue Decoupling

a. Introduction

In D.P.U. 07-50-A at 4-5, 32, 81-82, the Department directed each electric and gas distribution company to propose a full RDM in its future base distribution rate proceedings. The Department stated that the objective of revenue decoupling is the "elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts." D.P.U. 07-50-A at 4. The Department concluded that "a full decoupling mechanism best meets our objective of (1) aligning the financial interest of the companies with policy objectives regarding the efficient deployment of demand resources, and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources." D.P.U. 07-50-A at 31-32.

The Department approved an RDM for WMECo in its last base rate distribution proceeding. D.P.U. 10-70, at 55-59. WMECo's current revenue decoupling tariff ensures that it will collect a set amount of revenues annually (i.e., $132,415,739) through its distribution charge (M.D.P.U. No. 1050E, § 3).[67] The tariff caps the amount WMECo is allowed to collect from customers through the revenue decoupling adjustment factor ("RDAF") at one percent of total revenues (M.D.P.U. No. 1050E, § 6). All revenue exceeding this cap is then deferred for recovery to the following year to the extent there is room under the cap and subject to interest at the prime rate (M.D.P.U. No. 1050E, § 6).

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67 The RDM revenue requirement is distributed to the customer classes using the base distribution revenue allocator (M.D.P.U. No. 1050E, §, 4).

See, e.g., Western Massachusetts Electric Company, D.P.U. 16-175 (2017), Sch. A at 3; M.D.P.U. No. 1050E, § 6. NSTAR Electric currently does not have an RDM.

b. Companies Proposal

Eversource proposes a new RDM tariff, which would become effective February 1, 2018, to apply to both NSTAR Electric and WMECo (RR-DPU-51, Att. (a) at 324-328 (proposed M.D.P.U. No. 531)). Eversource proposes an RDM that is similar to WMECo's current RDM (RR-DPU-51, Att. (a) at 324-328). Eversource proposes to separately calculate the change in distribution revenue requirement for NSTAR Electric and WMECo customers, and allocate that change to each rate class on the basis of class contribution to distribution revenue, and further to the non-customer charge components within each rate class (Exh. ES-RDP-9, at 10; RR-DPU-51, Att. (a) at 325-327). The base distribution rates, set on a demand (per kW) and energy (per kWh) basis, as applicable for each rate class, would be adjusted proportionally to reach the target revenue for that class (Exh. ES-RPD-9, at 10; RR-DPU-51, Att. (a) at 325-327). Eversource proposes that no adjustment would be made to the customer charge (Exh. ESRDP-9, at 10).

Eversource notes two differences between WMECo's current RDM and the RDM proposed in this proceeding. First, Eversource would adjust target revenues on an annual basis as a result of the performance based revenue ("PBR") adjustment mechanism (Exh. ES-RDP-9, at 7, 11; RR-DPU-51, Att. (a) at 325-326). D.P.U. 17-05, at 334-414. Second, the Companies would adjust each year's target revenue to account for the sale of street lighting equipment (RR-DOER-3, Att.; RR-DPU-51, Att. (a) at 325). Eversource also proposes to revise its annual reporting requirements to be consistent with the RDAF reporting requirements that the Department approved in Investigation into Revenue Decoupling Adjustment Factor Filing Procedures, D.P.U. 14-RDAF-01, at 4-14 (2014), and to change the effective date for the RDAF in WMECO's current RDM tariff of February 1st to January 1st (Exhs. DPU-15-3; DPU-66-1; RR-DPU-51, Att. (a) at 326-328).

c. Positions of the Parties

Eversource argues that its proposal is essentially a continuation of the existing RDM applicable to WMECo and an extension of that RDM to include NSTAR Electric (Companies Brief at 33-34).

Eversource contends that the Department should approve the RDM as proposed because it is appropriately structured to promote the efficient deployment of energy efficiency and demand resources as contemplated by D.P.U. 07-50-A, and is consistent with Department precedent (Companies Brief at 35). In particular, Eversource asserts that its proposal to adjust the decoupling revenues to account for the sale of street lighting equipment is consistent with the method that the Department approved for Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-136-A (2016) (Companies Brief at 35). No other party addressed Eversource's revenue decoupling proposal.

d. Analysis and Findings

The Department has reviewed Eversource's proposed RDM and finds that it is structured to operate in a similar manner to WMECo's current RDM, which was approved in

D.P.U. 10-70, at 55-59 (RR-DPU-51, Att. (a) at 324-328; M.D.P.U. No. 1050E). Regarding the two differences between WMECo's current RDM and the RDM proposed in this proceeding, we first consider Eversource's proposal to increase its target revenues on an annual basis for the revenue adjustment allowed pursuant to the Companies' PBR mechanism. In the D.P.U. 17-05 Order, the Department approved Eversource's proposal to annually adjust its distribution revenues using the PBR mechanism. D.P.U. 17-05, at 412-413. The proposed RDM allows the Companies to recover their allowed distribution revenues, dollar for dollar (RR-DPU-51, Att. (a) at 326-327). Since the allowed distribution revenues will be adjusted each year by the PBR mechanism, the Department also finds it appropriate to adjust the target distribution revenues annually for the adjustment from the PBR mechanism.

Next, the Department considers Eversource's proposal to adjust the decoupling revenues to account for the sale of street lighting equipment. In the instant filing, Eversource proposes to collect through base rates \$4,136,071 and \$5,484,808 from S-1 customers and \$2,501,826 and \$127,333 from S-2 customers for NSTAR Electric and WMECo, respectively (RR-DPU-51, Att. (a) at 326). As discussed in Section IV.K.4.a below, customers in the S-1 rate class (company-owned street lighting equipment) pay a different distribution rate from customers in the S-2 rate class (municipally-owned street lighting equipment) because customers in the S-1 rate class are paying for the capital costs associated with the street lighting equipment used to serve them, whereas customers in the S-2 rate class own the street lighting equipment (Exh. ES-RDP-7 (ALT1), Sch. 1; RR-DPU-50).

As the Department noted in D.P.U. 15-155, at 30, revenue decoupling was not intended to compensate a company for the sale of street lighting assets. See also, D.P.U. 14-136-A, at 10; D.P.U. 07-50-A.[68] The Department did not contemplate this potential issue, and the model we adopted to decouple rates for all future ratemaking proceedings was silent on street lighting rate classes in RDM. D.P.U. 07-50-B at 26. In D.P.U. 15-155, at 30-31 the Department placed all electric distribution companies on notice regarding concerns with the inclusion of street lighting rate classes in RDMs,[69] and that we would consider removing street lighting rate classes from RDMs in each electric distribution company's next base distribution rate proceeding. Further, we directed each electric distribution company, as part of the initial filing in its next base distribution rate proceeding, to address and provide justification for the continued inclusion of street lighting rate classes in each company's respective RDM. D.P.U. 15-155, at 31.

In response to the Department's directive, Eversource proposes an adjustment to the actual revenues for its street lighting rate classes that is used to calculate its RDM adjustment

68 The Department determined that an adjustment to National Grid's RDM was necessary to account for the sale of street lighting assets. D.P.U. 14-136-A at 10-11. National Grid agreed to adjust the annual target revenue in its RDM by a fixed percentage of proceeds from street lighting sales according to vintage year that value the revenue requirement of the proceeds from sales in a manner consistent with the Company's current street lighting base rates. D.P.U. 14-136-A at 5, 11-12.

69 Specifically, the Department was concerned that the revenues collected through the RDM were unintentionally compensating companies for the lost revenues associated with the sale of street lighting assets, where the companies already were compensated for these street lighting assets through the proceeds of the sale of the equipment. D.P.U. 15-155, at 30-31.

to account for the sale of street lighting assets (Tr. 11, at 2232; RR-DPU-51, Att. (a) at 325). The Companies propose this adjustment to equal the proceeds that it receives from the sale of its street lighting equipment multiplied by the avoided cost of no longer owning, operating, and maintaining such equipment, stated as a percentage (RR-DPU-51, Att. (a) at 325). We find that this proposed adjustment is consistent with the method that the Department approved for National Grid in D.P.U. 14-136-A, at 10-12, and is appropriate for Eversource. Therefore, the Department approves the Companies' proposed adjustment to its RDM to account for the sale of its street lighting assets.

Based on the above findings, the Department approves Eversource's proposed RDM for effect February 1, 2018. The Department directs Eversource in its compliance filing to update its initial base revenue target and its base distribution revenue allocator to be consistent with the directives set forth in this Order.

4. Energy Efficiency Charges Tariff

a. Introduction

Electric energy efficiency Program Administrators, including Eversource, fund energy efficiency plan implementation from the following sources: (1) a mandatory \$0.0025 per kilowatt-hour ("kWh") system benefits charge ("SBC");[70,71] (2) revenues from the forward

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70 The SBC charge is fixed at 0.250 cents per kWh and is collected from all electric distribution customers pursuant to G.L. c. 25, § 19(a). Guidelines, § 2.16.

71 There are a variety of synonyms for the charges identified in the various energy efficiency tariffs. For example, NSTAR Electric's current energy efficiency charges tariffs refer to the SBC as the "energy efficiency charge" or "EEC" (M.D.P.U. Nos. 107F, 207F, 307H). WMECo's current energy efficiency charges

capacity market ("FCM") administered by ISO-NE; (3) revenues from cap and trade pollution control programs (e.g., Regional Greenhouse Gas Initiative ("RGGI")); (4) other funding sources; and (5) an energy efficiency surcharge, most commonly known as an energy efficiency reconciliation factor ("EERF").[72] Guidelines, § 3.2.1;[73] see also G.L. c. 25, § 19(a). If sufficient funding is not available from the first four funding sources, the Department may approve the collection of additional funding from electric ratepayers through the EERF, where certain conditions are met (i.e., after consideration of rate and bill impacts on consumers and whether past programs have lowered the cost of electricity). G.L. c. 25, § 19(a); Guidelines, § 3.2.1.6.2.

The EERF is a component of the Companies' energy efficiency charges tariffs (M.D.P.U. Nos. 107F, 207F, 307H; M.D.P.U. No. 1043H). On an annual basis, the Companies submit updated EERFs for Department review, based on: (1) the most recent

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tariff refers to the SBC as the "demand-side management adjustment rate" or "DSM adjustment" (M.D.P.U. No. 1043H). Eversource's proposed energy efficiency charges tariff refers to the SBC as the "energy conservation charge" or "ECC" (RR-DPU-51, Att. (a) at 103-106 (proposed M.D.P.U. No. 520)). In order to avoid confusion and ensure consistency with the terminology used in the Department's energy efficiency guidelines, in its final energy efficiency charges tariff Eversource shall cross-reference the term "systems benefit charge," as defined in Guidelines, § 2.16, in its definition of "energy conservation charge."

72 NSTAR Electric currently refers to its energy efficiency surcharge as an EERF (M.D.P.U. Nos. 107F, 207F, 307H). WMECo refers to this same charge as an "energy efficiency program cost adjustment" or "EEPCA" (M.D.P.U. No. 1043H). In this section, the Department refers to the energy efficiency surcharge as the EERF.

73 The Department's current energy efficiency guidelines ("Guidelines") were established in Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 11-120-A, Phase II (2013).

projections of energy efficiency budgets, revenues from non-EERF funding sources (i.e., SBC revenues, FCM revenues, RGGI funds, other funding), and sales for the current year; and (2) a reconciliation of any under- or over-recovery of actual costs from the previous year.[74] Any positive or negative balance (excluding any income tax adjustment) accrues interest calculated at the customer deposit rate (M.D.P.U. Nos. 107F, 207F, 307H; M.D.P.U. No. 1043H).

The Companies calculate the EERF separately for each customer class (i.e., residential, low income residential, C&I). The EERF revenues required to fund the low income energy efficiency programs are allocated to each customer class using the applicable base distribution revenue allocators approved in the most recent base rate case (M.D.P.U. Nos. 107F, 207F, 307H; M.D.P.U. No. 1043H).

NSTAR Electric's current energy efficiency charges tariffs differ from WMECo's tariff in three ways. First, NSTAR Electric's tariffs include a lost base revenues ("LBR") component in the EERF formula to collect Department-approved incremental kWh savings resulting from energy efficiency programs (M.D.P.U. Nos. 107F, 207F, 307H).[75] Second, NSTAR Electric's tariffs provide that separate EERFs shall be calculated and charged to

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[74] Final reconciliation of the Companies' EERFs takes place after the close of the then-current three-year energy efficiency plan term. Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 11-120-A, Phase II, at 20 (2013).

[75] WMECo implemented revenue decoupling in its last rate case, D.P.U. 10-70, and, therefore, does not recover LBR.

distribution customers in municipalities served by a municipal aggregator that is also an energy efficiency program administrator (i.e., Cape Light Compact) (M.D.P.U. Nos. 107F, 207F, 307H).[76] Finally, unlike WMECo, NSTAR Electric's tariffs set the EERF to zero in the event that the calculation results in a credit to customers (i.e., NSTAR Electric's EERFs can only be a charge to customers and not a credit) (M.D.P.U. Nos. 107F, 207F, 307H).

b. Companies Proposal

The Companies propose to adopt a single energy efficiency charges tariff, M.D.P.U. No. 520, applicable for both NSTAR Electric and WMECo, for effect February 1, 2018 (RR-DPU-51, Att. (a) at 103-106; see Motion to Delay Implementation of Rates at 1-2). The proposed tariff adopts NSTAR Electric's current method of calculating the EERF, which includes a component in the EERF formula for recovery of Department-approved LBR (RR-DPU-51, Att. (a) at 103-106).[77] The proposed tariff also adopts the language in NSTAR Electric's current energy efficiency charges tariffs regarding the calculation of a separate EERF for customers served by a municipal aggregator with an approved energy efficiency plan (Exh. RR- DPU-51, Att. (a) at 103). Finally, the proposed energy efficiency charges tariff retains the language in NSTAR Electric's current tariffs that sets the EERF to zero in

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76 Early references to "municipal aggregator" in NSTAR Electric's tariff omit reference to an approved energy efficiency plan although this language is included on a later page (see, e.g., RR-DPU-51, Att. (a) at 103, 104, 106).

77 The Companies maintain that NSTAR Electric is eligible to recover LBR related to the annual incremental kWh savings resulting from energy efficiency programs through the end of plan-year 2017 (i.e., prior to the implementation of revenue decoupling) (Exh. ES-DPH-1, at 185-186). LBR for plan-year 2017 would be collected through the EERF starting July 1, 2018 (Exh. ES-DPH-1, at 185-186).

the event that the calculation would result in a credit to customers (RR-DPU-51, Att. (a) at 105).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should deny the Companies' proposal to include LBR as a component of the EERF (Attorney General Brief at 26). According to the Attorney General, recovery of LBR together with revenue decoupling would constitute "double-recovery" of lost distribution revenues (Attorney General Brief at 26-27). More specifically, the Attorney General maintains that revenue decoupling will ensure that the Companies collect their target revenues (Attorney General Brief at 27). Therefore, the Attorney General argues that, regardless of the Companies' sales and the effect of their energy efficiency programs on distribution revenues, Eversource will be made whole for any lost distribution revenues through revenue decoupling (Attorney General Brief at 27). The Attorney General maintains that WMECo implemented revenue decoupling in its last rate case and, therefore, has not needed a separate revenue decoupling mechanism to recover LBR (Attorney General Brief at 27-28). According to the Attorney General, the Companies propose to "have the best of both worlds" and charge ratepayers revenue decoupling adjustment and LBR for both NSTAR Electric and WMECo (Attorney General Brief at 28).

In addition, the Attorney General maintains that neither NSTAR Electric nor WMECo should be recovering LBR at this time because it is inconsistent with previous Department directives (Attorney General Reply Brief at 6). Specifically, the Attorney General asserts that in D.P.U. 10-170-B at 49, the Department found that "neither NSTAR Gas nor NSTAR Electric will be allowed to recover any LBR after the end of the Base Rate Freeze period on December 31, 2015" (Attorney General Reply Brief at 6). The Attorney General asserts that, by the time that new rates will go into effect, NSTAR Electric should have fully recovered any LBR associated with incremental kWh savings achieved on or before December 31, 2015 (Attorney General Reply Brief at 6-7). The Attorney General argues that the Department should ensure that Eversource has complied with the Department's directives in D.P.U. 10-70-B at 49 prohibiting LBR recovery and, if not, should require NSTAR Electric to return to ratepayers any LBR collected for incremental kWh savings achieved after December 31, 2015 (Attorney General Reply Brief at 7).

ii. Companies

The Companies maintain that the Attorney General's assertion that Eversource proposes to recover NSTAR Electric's energy efficiency-related revenue losses both through LBR and through revenue decoupling is false (Companies Brief at 43). According to the Companies, NSTAR Electric's LBR will no longer be recorded after revenue decoupling is implemented on January 1, 2018 (Companies Brief at 43, citing Exh. ES-DPH-1, at 185).[78]

In addition, Eversource refutes the Attorney General's claim that NSTAR Electric was required to stop collecting LBR after December 31, 2015 (Companies Reply Brief at 13-18). The Companies argue that the directive cited by the Attorney General was part of a merger

[78] The Companies assert that NSTAR Electric's 2017 LBR will be recovered through the EERF beginning on July 1, 2018 (Companies Brief at 43).

proceeding and that there was insufficient process and record in the merger case to render a decision regarding the recovery of LBR after December 31, 2015 (Companies Reply Brief at 15). Specifically, the Companies maintain that there was no notice to the parties that recovery of LBR after December 31, 2015, was at issue in the review of the settlements in D.P.U. 10-170-B (Companies Reply Brief at 15). Further, the Companies assert that the language relied upon by the Attorney General in support of her position references Article II (7) of the settlement agreement between the Attorney General and DOER (Companies Reply Brief at 16). The Companies contend that Article II (7) addresses the "special methodology" NSTAR Electric would use to calculate LBR during the base rate freeze period (Companies Reply Brief at 16). Accordingly, Eversource maintains that the Department's directive in D.P.U. 10-170-B at 49 could have no other meaning than to confirm that neither NSTAR Electric nor WMECo would be eligible to calculate LBR using the method established in Article II (7) after December 31, 2015 (Companies Reply Brief at 16). However, the Companies assert that the settlement is silent as to recovery after December 31, 2015 (Companies Reply Brief at 16).

Finally, Eversource argues that NSTAR Electric's Department-approved three-year energy efficiency plan for 2016 through 2018 expressly provides for the recovery of LBR (Companies Reply Brief at 17, citing 2016-2018 Three-Year Plans, D.P.U. 15-160 through D.P.U. 15-169 (2016); Exh. Eversource Energy-2, at 45-46, 52-58). The Companies contend that the Attorney General had multiple opportunities to challenge NSTAR Electric's LBR recovery in the three-year plan proceeding but did not (Companies Reply Brief at 18).

d. Analysis and Findings

It is undisputed that companies are not eligible to record and recover LBR for any energy efficiency related kWh savings realized after the implementation of revenue decoupling. D.P.U. 07-50-A at 82, 83 n.24; D.P.U. 07-50-B at 33-35. In light of NSTAR Electric's proposal to implement revenue decoupling in this proceeding, the Attorney General raises two arguments related to LBR. First, the Attorney General asserts that the Department should deny Eversource's proposal to include LBR as a component of the EERF formula in the energy efficiency charges tariff post-revenue decoupling to prevent a double-recovery of energy efficiency-related lost revenues (Attorney General Brief at 26-27). Second, the Attorney General argues that, pursuant to a Department directive in D.P.U. 10-170-B at 49, neither NSTAR Electric nor WMECo are eligible to recover any LBR realized after December 31, 2015 (Attorney General Reply Brief at 7). The Companies dispute each of the Attorney General's arguments and maintain that their proposed energy efficiency charges tariff appropriately accounts for recovery of eligible LBR through the EERF (Companies Brief at 43; Companies Reply Brief at 13-18). No other party addressed this issue on brief.

Pursuant to Guidelines, § 3.3.1, Eversource included projected LBR for NSTAR Electric as part of its proposed energy efficiency budget for each year of its most recent three-year energy efficiency plan (i.e., 2016 through 2018). D.P.U. 15-160 through D.P.U. 15-169 (Exh. Eversource Energy-2, at 45-46, 52-58). Although LBR recovery was not expressly addressed in the Order approving the three-year energy efficiency plan, the

Department approved NSTAR Electric's three-year estimated EERF, which contained projected LBR. D.P.U. 15-160 through D.P.U. 15-169 at 168. In addition, Eversource included LBR related to unverified 2016 kWh savings for NSTAR Electric as part of its 2017 EERF filing. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-102 (2017) (Exh. NSTAR-ANB-1).[79]

On June 28, 2017, the Department approved the Companies' 2017 EERF filing subject to reconciliation after further investigation. D.P.U. 17-102, at 3. Pursuant to Guidelines, § 4.1.2, subject to the results of the investigation of the Companies' forthcoming energy efficiency three-year term performance report for 2016 through 2018, the Department will approve recovery of (1) actual costs incurred during the term, (2) actual performance incentive payments earned during the term, and (3) actual LBR during the term, where applicable. D.P.U. 11-120 Phase II at 6-7.[80] Accordingly, the Department finds that the

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79 The Department notes that the Attorney General raised no concern with the inclusion of projected LBR for NSTAR Electric as part of the 2016-2018 Joint Statewide Energy Efficiency Plan. Rather, as a member of the Energy Efficiency Advisory Council ("Council") and as an intervenor in the Department's investigation of the three-year plans, the Attorney General offered support for the statewide plan as filed. D.P.U. 15-160 (Attorney General Initial Brief at 17). In fact, the Attorney General notes in her brief that further refinements to the statewide plan were made by the Program Administrator at the request of the Council and a revised version of the statewide plan was filed with the Council on October 23, 2015, which was subsequently approved by Council resolution dated October 26, 2015. D.P.U. 15-160 (Attorney General Initial Brief at 5).

80 The Companies' term report for 2016 through 2018 will be filed no later than August 1st in 2019. See Order Approving Energy Efficiency Three-Year Term Report Template, D.P.U. 11-120-B at 9.

correct place for the Attorney General to raise issues related to the Companies' LBR is the three-year term performance report proceeding.

Because projected LBR are included as part of NSTAR Electric's plan-year budgets for 2016 through 2018 and as part of the 2017 EERFs approved subject to reconciliation, the Department finds that it is appropriate to retain an LBR component as part of the EERF formula at this time. Inclusion of an LBR component in the EERF formula post-revenue decoupling does constitute double recovery of energy efficiency-related lost revenues as claimed by the Attorney General. However, all LBR at issue are related to kWh savings achieved in plan years prior to the implementation of revenue decoupling for NSTAR Electric. In addition, inclusion of an LBR component in the EERF formula does not guarantee cost recovery; instead, it establishes a method to collect projected LBR subject to the results of the Department's investigation of the Companies' three-year term report.

As the Companies acknowledge, WMECo has implemented revenue decoupling and, therefore, no longer collects LBR (Companies Reply Brief at 14, citing D.P.U. 10-70, at 40-55). Further, NSTAR Electric will no longer be eligible to request LBR recovery for energy efficiency-related savings achieved after the implementation of revenue decoupling in this case (Exh. ES-DPH-1, at 185). Accordingly, Eversource shall modify its proposed energy efficiency charges tariff to clarify that: (1) any request to recover Department-approved LBR shall be limited to energy efficiency-related savings for NSTAR Electric only; and (2) NSTAR Electric shall cease to record LBR for potential recovery as of the date it implements revenue decoupling in this case.[81] Further, because all remaining LBR at issue are solely related to savings achieved from NSTAR Electric's energy efficiency activities, we find that it is appropriate for Eversource to recover these costs from NSTAR Electric customers only. Accordingly, Eversource shall modify its proposed energy efficiency charges tariff to indicate that separate EERFs will be calculated and charged to customers in NSTAR Electric's service area to collect any remaining Department-approved LBR.

After review, the Department finds that several additional changes to the Companies' proposed energy efficiency charges tariff are necessary. First, as addressed in n.71 above, in order to avoid confusion and ensure consistency with the terminology used in the energy efficiency guidelines, Eversource shall modify its proposed energy efficiency charges tariff to cross-reference the term "systems benefit charge," as defined in Guidelines, § 2.16, in its definition of "energy conservation charge." Second, Eversource shall omit the language in of the proposed tariff specifying that when the EERF is calculated to be less than zero, it shall be set to zero (RR-DPU-51, Att. (a) at 105). Such language does not appear in the other Program Administrators' energy efficiency charges tariffs (including WMECo's), and the Companies have not demonstrated why such language is necessary or appropriate (see M.D.P.U. No. 1043H; M.D.P.U. No. 287 (Fitchburg Gas and Electric Light Company d/b/a

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81 It is anticipated that the June 2018 EERF filing for rates effective July 1, 2018 will be the last filing containing LBR for energy efficiency savings achieved by NSTAR Electric prior to the implementation of revenue decoupling (Exh. ES-DPH-1, at 185-186).

Unitil); M.D.P.U. No. 1340 (Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid)). Third, as discussed above, the Companies propose to adopt the language in NSTAR Electric's current energy efficiency charges tariffs regarding the calculation of a separate EERF for customers served by a municipal aggregator with an approved energy efficiency plan; however, early references in the proposed tariff to "municipal aggregator" omit reference to "approved energy efficiency plan" (see, e.g., RR-DPU-51, Att. (a) at 103, 104, 106). Accordingly, Eversource shall modify its proposed energy efficiency charges tariff to clarify that all references to "municipal aggregator" in the tariff are to a municipal aggregator with an approved energy efficiency plan. Finally, in order to avoid confusion, Eversource shall remove language in the proposed tariff indicating that the "EERF shall be established once every three years" as part of the three-plan plan approval process (RR-DPU-51, Att. (a) at 106).[82]

Subject to the changes required herein, the Department finds that Eversource's proposed energy efficiency charges tariff is consistent with applicable law and Department precedent. G.L. c. 164; G.L. c. 25 §§ 19 (a), 19(b)(1), 19(b)(2); Guidelines. Eversource

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82 As discussed above, in the three-year plan proceedings, the Department renews the prerequisite findings to approve collection of additional funding from electric ratepayers through the establishment of an EERF mechanism (i.e., after consideration of rate and bill impacts on consumers and whether past programs have lowered the cost of electricity). G.L. c. 25, § 19(a); Guidelines § 3.2.1.6.2. The Department established that EERFs rate adjustments and reconciliations would be set on an annual basis. D.P.U. 15-160 through D.P.U. 15-169 at 113.

shall file a revised energy efficiency charges tariff in its compliance filing consistent with the above directives.

5. Other Reconciling Mechanisms

a. Introduction

Eversource proposed several tariff changes that affect the eleven reconciling mechanisms that NSTAR Electric currently has in effect and the 13 reconciling mechanisms that WMECo has in effect (Exhs. ES-RDP-9, at 31-32; ES-RDP-10, at 1; RR-DPU-51, Att. (a)).[83,84] In addition, the Department approved the Companies' proposal to adopt a storm reserve adjustment mechanism. D.P.U. 17-05 Order at 558-559.[85] Further, we directed Eversource to develop a new reconciliation mechanism to recover the cost of its vegetation

83 NSTAR Electric currently has the following reconciling mechanisms: (1) basic service reconciliation adjustment; (2) transmission service cost adjustment; (3) transition service cost adjustment; (4) energy efficiency recovery factor; (5) pensions/post-retirement benefits other than pensions adjustment factor; (6) residential assistance adjustment factor; (7) storm cost recovery adjustment factor; (8) net metering recovery surcharge; (9) long-term renewable contract adjustment; (10) Attorney General consultant expense provision; and (11) solar expansion cost recovery mechanism.

84 WMECo currently has the following reconciling mechanisms: (1) exogenous cost adjustment mechanism; (2) basic service reconciliation adjustment; (3) transmission service cost adjustment; (4) transition service cost adjustment; (5) energy efficiency recovery factor; (6) pension/PBOP adjustment factor; (7) residential assistance adjustment factor; (8) storm cost recovery adjustment factor; (9) solar program cost adjustment; (10) net metering recovery surcharge; (11) long-term renewable contract adjustment; (12) Attorney General consultant expense provision; and (13) solar expansion cost recovery mechanism.

85 The Department denied the Companies' request to implement a municipal property tax adjustment mechanism ("MPTA"). D.P.U. 17-05 Order at 525.

management pilot program. D.P.U. 17-05 Order at 582-584. Current and proposed tariffs for the reconciling mechanisms are outlined in the table below.[86]

Reconciling Mechanism		**Cancels M.D.P.U. No.:**		**M.D.P.U. No.: (Effective February 1, 2018)**
		(WMECo)	**(NSTAR Electric)**	
Exogenous Cost Adjustment Mechanism	ECAM	1042A	-	-
Basic Service Cost True-Up Factor	BSTF	1026BD[87]	104F 204F 304F	517
Transmission Service Cost Adjustment		1028B	105 205 305	518
Transition Cost Adjustment		1027B	106 206 306	519
Energy Efficiency Charge/Energy Efficiency Recovery Factor	EEC/EERF	1043G	107F 207F 307H	520
Pension/PBOP Adjustment Mechanism	PAF	1041I	109A 209A 309A	522
Residential Assistance Adjustment Factor	RAAF	1040J	110C 210C 310C	523
Eastern Massachusetts Storm Cost Recovery Adjustment Factor	ESCRAF	-	116D	116E
Western Massachusetts Storm Cost Recovery Adjustment Factor	WSCRAF	1054B	-	1054C
Storm Reserve Adjustment Factor	SRAF	-	-	524
Solar Program Cost Adjustment	SPCA	1044E	-	525
Net Metering Recovery Surcharge	NMRS	1048F	163C	527
Long-Term Renewable Contract Adjustment	LTRC	1051B	164B	528
Attorney General Consultant Expense Provision	AGCE	1053B	513A	530
Municipal Property Tax Adjustment	MPTA	-	-	534
Solar Expansion Cost Recovery Mechanism	SECRM	1058	537	537A

86 Source: RR-DPU-51.

87 The basic service reconciliation adjustment for WMECo is currently a provision of its basic service tariff, M.D.P.U. No. 1026BD. The Companies propose to move the basic service cost reconciliation adjustment to a separate tariff, proposed M.D.P.U. No. 517, effective February 1, 2018 (see RR-DPU-51, Att. (a) at 99-100).

b. Companies Proposal

Effective February 1, 2018, Eversource proposes the following for its reconciling rates: (1) to allocate costs using separate revenue requirements for NSTAR Electric and WMECo, and using the legacy rate classes; (2) to combine the NSTAR Electric and WMECo tariffs into a single tariff for each reconciling mechanism;[88] (3) to align all operational differences that currently exist between each company's reconciliation mechanisms;[89] and (4) to standardize the language used in the tariff for each reconciling mechanism (see Exh. ES-RDP-9, at 31; RR-DPU-51, Att. (a)). In addition, Eversource proposes to develop separate allocation factors for 2018 and 2019 to be consistent with its rate class consolidation and alignment proposal (RR-DPU-50, Att. at Exhs. ES-RDP-3(ALT1)(West) WP RDP-10; ES-RDP-3(ALT1)(East) WP RDP-10; ES-RDP-2(ALT1), WP RDP-6).

Effective January 1, 2019, Eversource proposes to combine the revenue requirement of NSTAR Electric and WMECo for each of their reconciling rates (Exh. DPU 56-9, at 2

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88 For example, currently, WMECo, Boston Edison Company, Commonwealth Electric Company, and Cambridge Electric Light Company all have separate basic service reconciliation adjustment factor tariffs (M.D.P.U. No. 1026BD, M.D.P.U. No. 104F, M.D.P.U. No. 204F; M.D.P.U. No. 304F, respectively). Effective February 1, 2018, Eversource proposes to merge these tariffs into one tariff (RR-DPU-51, Att. (a) at 99-100 (proposed M.D.P.U. No. 517)).

89 For example, NSTAR Electric's current residential assistance adjustment clause tariff allows NSTAR Electric to include forecasted arrearage management program ("AMP") expenditures (M.D.P.U. No. 110C; M.D.P.U. No. 210C; M.D.P.U. No. 310C); whereas, WMECo's current residential assistance adjustment clause tariff does not include forecasted AMP expenditures (M.D.P.U. No. 1040J). The Companies propose to include forecasted AMP expenditures in the consolidated residential assistance adjustment tariff (Exh. ES-RDP-9, at 31-34).

(Supp.)). The Companies proposed that the costs would be allocated using the combined revenue requirement for NSTAR Electric and WMECo, and using the consolidated and aligned rate classes (Exh. ES-RDP-2 (ALT1), WP RDP-6; RR-DPU-50).

c. Positions of the Parties

i. Cape Light Compact

Cape Light Compact argues that the revised rate design proposal for recovery of reconciling rate revenues results in an unjustified and inequitable cost shift (Cape Light Compact Brief at 21). Specifically, Cape Light Compact does not support combining the revenue requirement of NSTAR Electric and WMECo for the following reconciling rates: pension adjustment factor ("PAF"), storm cost recovery adjustment factor ("SCRAF"), transition cost adjustment, EERF, NMRS, and residential assistance adjustment factor ("RAAF") (Cape Light Compact Brief at 21-22). Cape Light Compact is concerned that the Companies' proposed treatment in the revised proposal would reduce the allocation of revenues to non residential customers by $11,000,000 for the reconciling mechanisms for NSTAR Electric and WMECo compared to maintaining separate revenue requirements, as the Companies proposed in their initial filing (Cape Light Compact Brief at 22). Meanwhile, Cape Light Compact claims that the Companies' proposed alternative treatment would increase the revenues of the reconciling mechanisms for NSTAR Electric's residential customers by over $14,000,000 (Cape Light Compact Brief at 22, citing Exhs. DPU-12-10; DPU-63-1).

Cape Light Compact notes that the Companies do not dispute the $11,000,000 figure (Cape Light Compact Brief at 23). Cape Light Compact underscores that Eversource admitted that the shift in reconciling rate revenue from WMECo's non-residential customers to NSTAR Electric's residential customers was not purposeful (Cape Light Compact Brief at 23, citing Tr. 16, at 3329). Accordingly, Cape Light Compact contends that the resulting shift is arbitrary and inequitable (Cape Light Compact Brief at 23). Therefore, Cape Light Compact argues that the Department should defer the consolidation of the NSTAR Electric and WMECo revenue requirements for the PAF, SCRAF, transition cost adjustment, EERF, NMRS, and RAAF until the Companies' next distribution rate case (Cape Light Compact Brief at 24).

ii. Companies

Eversource argues that Cape Light Compact's criticisms are not justified (Companies Brief at 49). The Companies argue that the elimination of LBR and the sharing with NSTAR Electric and WMECo of the revenue requirement for transmission and all reconciling rates will result in a decrease of approximately $17,000,000 to NSTAR Electric's residential customers and an increase of approximately $4,700,000 to WMECo's residential customers when reconciling mechanism revenues from 2018 are compared to revenues from 2019 (i.e., after the consolidation of the PAF, SCRAF, transition cost adjustment, EERF, NMRS, MPTA, and RAAF) (Companies Brief at 51).

d. Analysis and Findings

i. Introduction

In D.P.U. 17-05, the Department approved the merger of NSTAR Electric and WMECo into NSTAR Electric, which amounted to a legal consolidation of these two affiliates within its parent holding company. D.P.U. 17-05 Order at 30, 43-44. Since the approval of the merger of their respective holding companies in D.P.U. 10-170-B, NSTAR Electric and WMECo have been operating on a consolidated basis for such functions as day-to-day field operations, capital-investment planning, electric field operations, electric system operations, resource planning, and emergency response planning. D.P.U. 17-05 Order at 30. Previously, in 2006, the Department approved the legal consolidation of the NSTAR Electric legacy companies into NSTAR Electric. Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company Merger, D.T.E. 06-48 (2006). Similarly, these companies had been operating on a consolidated basis since the merger of their respective holding companies in 1999. D.T.E. 99-19. The Department finds it consistent with the current corporate and operational structure within Eversource for each reconciling rate mechanism for NSTAR Electric and WMECo to be combined into a single tariff. Also, this alignment provides economies and efficiencies in the Companies' administration of its tariffs and in filings with the Department. In addition, the Department finds it appropriate, effective February 1, 2018, for costs to be allocated to each reconciling rate mechanism using separate revenue requirements for NSTAR Electric and WMECo.[90]

Further, consistent with our findings stated above, the Department finds it appropriate, effective January 1, 2019, for costs to be allocated to each reconciling rate mechanism using a combined revenue requirement for NSTAR Electric and WMECo. Also, in examining a representative allocation of 2018 and 2019 residential revenue for the reconciling rate mechanisms by the NSTAR Electric and WMECo territories, we find that any differences are not unreasonable (RR-DPU-50(f))(2019); RR-DPU-50(e)(2018)). In making this finding, the Department takes into account the associated revenue requirements for all reconciling rate mechanisms, with the inclusion of transmission service cost adjustment and the exclusion of LBR for NSTAR Electric. Cape Light Compact did not take into account the inclusion of the transmission service cost adjustment or the exclusion of LBR for NSTAR Electric in its arguments pertaining to combining the revenue requirements.

Notwithstanding our findings in favor of unified tariffs for reconciling rate mechanism and of combined revenue requirements, the Department finds, as addressed below, that it is appropriate for NSTAR Electric and WMECo to maintain separate reconciling rate mechanisms and separate revenue requirements for the recovery of deferred storm costs.

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90 Currently, NSTAR Electric calculates separate transition charges with separate revenue requirements for Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company. See, e.g., NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 15-152 (Exhs. BOS-BKR-1, at 1; CAM-BKR-1, at 1; SOUTH-BKR-1, at 1).

Below, in addition to discussing the need for separate rate reconciling mechanisms for NSTAR Electric and for WMECo related to storm cost recovery, the Department addresses specific rate reconciling mechanisms and issues related to the adoption of single tariffs for each mechanism.

Also, the Department addresses in separate sections of this Order three reconciling mechanisms in which parties raise additional issues (i.e., the transmission service cost adjustment, the EERF, and the NMRS). The Companies' proposed reconciling rate mechanisms not addressed below in other Sections of this Order are approved, i.e., basic service cost true-up factor ("BSRA"), transition cost adjustment, PAF, RAAF, SPCA, long-term renewable contract adjustment ("LTRCA"), Attorney General consultant expense provision ("AGCEF"), and solar expansion cost recovery mechanism ("SECRM"). For each of these rates except the transition cost adjustment, LTRCA, and PAF, we direct the Companies in their compliance filing to update the tariffs with the base distribution revenue allocator to comply with the revenue requirement approved for each rate class in this proceeding. For the PAF, we direct the Companies in their compliance filing to update the tariff with the labor allocator to comply with the labor allocator approved in this proceeding.[91] For the AGCEF, we direct the Companies in their compliance filing to revise the tariff to provide that costs are assigned to rate classes using the base distribution revenue allocator, and to state the base distribution revenue allocator to comply with the revenue

91 The transition charge and LTRCA are recovered through a flat kWh charge from all rate classes and as such have no rate class allocator.

requirement approved for each rate class in this proceeding. For the BSRA, we direct the Companies in their compliance filing to include language stating the interest rate as the customer deposit rate applicable to the monthly balance in the account.

ii. Exogenous Cost Adjustment Mechanism

The Companies propose to eliminate WMECo's exogenous cost adjustment mechanism ("ECAM"), M.D.P.U. No. 1042A (Exh. ES-RDP-9, at 34). According to Eversource, the recovery of exogenous costs, such as those recovered through the ECAM, would be subsumed, in part, by the PBR mechanism through the Z factor (Exh. ES-RDP-9, at 34; RR-DPU-51, Att. (a) at 332-333).[92] No party addressed this issue on brief.

The Department has reviewed the Companies' proposal to eliminate the ECAM. The Department is satisfied that the Companies have demonstrated that the ECAM is no longer warranted, and approves the elimination of WMECo's ECAM (Exh. ES-RDP-9, at 34; RR-DPU-51, Att. (a) at 332-333).

iii. WMECo's Storm Cost Recovery Adjustment Factor

Eversource proposes to cancel WMECo's current storm recovery reserve cost adjustment ("SRRCA") tariff, M.D.P.U. No. 1054B, and replace it with a SCRAF, proposed M.D.P.U. No. 1054C, effective February 1, 2018 (Exh. RR-DPU-51, Att. (a) at 119-121). Pursuant to the D.P.U. 10-70 Order and M.D.P.U. No. 1054B, WMECo's SRRCA currently recovers: (1) the storm fund deficit; and (2) the incremental funding of a reserve for the

[92] The Z factor is a component of the PBR formula that adjusts the target revenues for positive or negative changes to the Companies' costs that are beyond the Companies' control and not reflected in the gross domestic product price index (GDP-PI) or the other components of the PBR formula. D.P.U. 17-05 Order at 340.

recovery of storm costs. D.P.U. 10-70, at 198; M.D.P.U. No. 1054B at 1. Pursuant to annual SRRCA filings, WMECo reconciles its past period revenue requirement with interest at the customer deposit rate, and uses the base distribution revenue allocator to assign the revenue requirement to its rate classes (M.D.P.U. No. 1054B at 2). As of November 1, 2017, the Companies reported a storm reserve deficit of $8,324,052 in the SRRCA.[93] Western Massachusetts Electric Company, D.P.U. 17-162 (Exh. EVERSOURCE-12, at 1).

Pursuant to the proposed SCRAF, Eversource seeks to recover the incremental storm costs that WMECo incurred prior to January 1, 2018, in addition to any prior period balances associated with storm costs that the Department has approved for recovery (see RR-DPU-51, Att. (a) at 119-121 (proposed M.D.P.U. No. 1054C)).[94] The Companies do not propose to recover the incremental funding for a reserve fund through the SCRAF; rather, effective February 1, 2018, WMECo will begin recovering revenues for a reserve fund through base rates pursuant to the storm fund and the storm reserve adjustment mechanism, which the Department approved in the D.P.U. 17-05 Order at 563, as set forth in proposed M.D.P.U. No. 524 (RR-DPU-51, Att. (a) at 119-121). The Companies propose for WMECo's SCRAF to be effective February 1, 2018 and that WMECo recover during 2018 associated storm costs (i.e., incremental storm costs that WMECo incurred prior to

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93 The Department's review of WMECo's storm cost issues in D.P.U. 17-162 is pending.

94 These costs would be reconciled to the revenue collected through the SCRAF in the prior year plus carrying charges at the customer deposit rate on any over- or under-collection (Exh. RR-DPU-51, Att. (a) at 119-120).

January 1, 2018) from WMECo's customers only (RR-DPU-29, at 1; see RR-DPU-51, Att. (a) at 119-121). Effective January 1, 2019, Eversource proposes to allocate WMECo's SCRAF revenue requirement to both NSTAR Electric and WMECo customers (RR-DPU-51, Att. (a) at 120).

In the D.P.U. 17-05 Order at 561, the Department allowed WMECo to continue recovering storm-related costs through its annual reconciling factor, but delayed any determination on the tariff as it related to rate design. The Department now has reviewed the Companies' proposed SCRAF tariff for WMECo and finds it reasonable, with the exception of the proposed allocation of the revenue requirement across NSTAR Electric and WMECo and for rates effective January 1, 2019, which, as discussed below, we find would be inequitable and unfair. Finally, we direct the Companies in their compliance filing to update the base distribution revenue allocator in WMECo's SCRAF tariff to comply with the revenue requirement approved for each rate class in this proceeding and to state that the deferred monthly balance shall accrue interest at the customer deposit rate.

iv. NSTAR Electric's Storm Cost Recovery Adjustment Factor

NSTAR Electric's currently effective SCRAF, M.D.P.U. No. 116D recovers the incremental costs incurred to restore power for two 2011 storm events: (1) Tropical Storm Irene; and (2) a snowstorm that occurred in October 2011 (M.D.P.U. No. 116D, § 1.10). D.P.U. 10-170-B at 49-50; NSTAR Electric Company, D.P.U. 13-52 (2013). These costs were excluded from NSTAR Electric's storm fund calculation at the time and, instead, are recovered through the SCRAF over a five-year period beginning January 1, 2014, with carrying charges at the prime rate (see, e.g., M.D.P.U. No. 116D, § 1.01). The revenue requirement associated with these costs is allocated to each rate class using the base distribution revenue allocator (see, e.g., M.D.P.U. No. 116D, § 1.04).

Pursuant to the proposed SCRAF, Eversource seeks to recover the incremental storm costs that NSTAR Electric incurred associated with the two 2011 storms, as well as other incremental storm costs that NSTAR Electric incurred prior to January 1, 2018, and that the Department approved for recovery (RR-DPU-51, Att. (a) at 116-118 (proposed M.D.P.U. No. 116E)). Effective February 1, 2018, NSTAR Electric will begin recovering revenues for a reserve fund through base rates pursuant to the storm fund and the storm reserve adjustment mechanism, which the Department approved in the D.P.U. 17-05 Order at 563, as set forth in proposed M.D.P.U. No. 524 (RR-DPU-51, Att. (a) at 122-123). The Companies propose for NSTAR Electric's SCRAF to be effective February 1, 2018 and that NSTAR Electric recover during 2018 the aforementioned storm costs from NSTAR Electric customers only (RR-DPU-29, at 1; see RR-DPU-51, Att. (a) at 116-118). Effective January 1, 2019, Eversource proposes to allocate NSTAR Electric's SCRAF revenue requirement to both NSTAR Electric and WMECo customers (RR-DPU-51, Att. (a) at 117).

In the D.P.U. 17-05 Order at 561, the Department approved Eversource's proposal to recover all deferred storm costs incurred prior to January 1, 2018 through NSTAR Electric's SCRAF over a five-year period, but the Department delayed any determination on the tariff as it related to rate design. Additionally, the Department approved NSTAR Electric's proposal to recover any outstanding storm fund balance of approximately $105,000,000 for storms that have occurred since 2011 over a five-year period through NSTAR Electric's storm cost recovery reconciling mechanism. D.P.U. 17-05 Order at 560-561.[95] The Department has approved Eversource's proposal to recover these costs over a five-year period beginning February 1, 2018 and, during 2018, to recover these costs only from NSTAR Electric's customers. D.P.U. 17-05 Order at 560-561.

As noted above, effective January 1, 2019, Eversource proposes to allocate the SCRAF revenue requirement to customers of NSTAR Electric and WMECo (RR-DPU-29, at 1; RR-DPU-51, Att. (a) at 117, 120). The Department finds that the Companies' proposal is contrary to our rate design principle of fairness. While the Department has determined that it is appropriate to allow NSTAR Electric to begin recovering its significant outstanding storm balance of approximately $105,000,000, subject to prudence reviews and reconciliation, this significant balance represents costs incurred to restore power solely to NSTAR Electric customers. D.P.U. 17-05 Order at 560. The Department finds that it would be inequitable and unfair to require WMECo customers to incur a portion of NSTAR Electric's deferred storm costs, particularly where WMECo has deferred only a small amount of its storm costs. Therefore, the Department rejects the Companies' proposal to recover NSTAR Electric's SCRAF revenue requirement from NSTAR Electric and WMECo customers effective January 1, 2019. Likewise, the Department finds that it would be

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95 The Department is currently reviewing the prudence of these storm-related costs in NSTAR Electric Company, D.P.U. 16-74 and NSTAR Electric Company, D.P.U. 17-51. Storm-related costs approved in these proceedings would be recovered through NSTAR Electric's SCRAF.

inequitable and unfair for NSTAR Electric customers to incur any of WMECo's deferred storms costs. Instead, the Department directs Eversource to allocate NSTAR Electric's SCRAF only The Department finds that it would be inequitable and unfair to require WMECo customers to incur a portion of NSTAR Electric's deferred storm costs, particularly where WMECo has deferred only a small amount of its storm costs.[96] Therefore, the Department rejects the Companies' proposal to recover NSTAR Electric's SCRAF revenue requirement from NSTAR Electric and WMECo customers effective January 1, 2019. Instead, the Department directs Eversource to allocate NSTAR Electric's SCRAF only to NSTAR Electric's customers, and to allocate WMECo's SCRAF only to WMECo's customers. Finally, we direct the Companies in their compliance filing to update the base distribution revenue allocators listed in NSTAR Electric's SCRAF tariff to comply with the revenue requirement approved for each rate class in this proceeding.

v. Conclusion

The Department has reviewed the Companies' proposal to change their current reconciling mechanisms (Exhs. ES-RDP-9, at 34; DPU 56-9, at 2 (Supp.)). As indicated above, the Department approves the Companies' proposal to eliminate the ECAM. In addition, the Department approves the Companies' proposal to combine rate tariffs for NSTAR Electric and WMECo for effect February 1, 2018, and combine the revenue

96 As noted above, in D.P.U. 17-162, which is pending before the Department, WMECo seeks recovery of approximately $8,000,000 over the next five years for storm costs that occurred prior to January 1, 2018. D.P.U. 17-162 (Exh. EVERSOURCE-12, at 1).

requirement for effect January 1, 2019 with respect to the BSRA, the transition charge, the PAF, the RAAF, the SPCA, the LTRCA, the AGCEF, and the SECRM. Further, we reject the Companies' proposal to recover NSTAR Electric's SCRAF revenue requirement from NSTAR Electric and WMECo customers, and WMECo's SCRAF revenue requirement from NSTAR Electric and WMECo customers effective February 1, 2018. The Department directs Eversource in its compliance filing to comply with the above directives regarding the reconciling mechanisms. Consistent with our finding in Cost Based Reconciling Mechanisms, D.P.U. 12-126-A through 12-126-I, at 31-32 (2013), the Department directs the Companies in their compliance filing to implement the change to the allocation factors in the reconciling mechanisms for all reconciling mechanisms with tariff changes or rate changes effective February 1, 2018.

I. Basic Service Procurement and Rates

1. Introduction

Eversource proposes to maintain its basic service rate offerings during the proposed rate alignment and consolidation (Exh. ES-RDP-1, at 34). Eversource states that it will procure basic service based on the ISO-NE load zones in eastern and western Massachusetts, and it will charge customers separate pricing based on the results of these procurements (Exhs. ES-RDP-1, at 34; CLC-1-3; CLC-9-1).[97] However, the Companies state the proposed consolidation of rate classes necessitates a re-classification of the rate classes that are classified as commercial versus industrial (Exh. ES-RDP-1, at 34). Specifically, they note

97 The Companies' treatment of basic service pricing is the same in both the initial rate design proposal and revised rate design proposal (Exh. CLC-9-1).

that basic service pricing for commercial customers is in effect for six months on a fixed basis, but industrial customers face variable pricing that is set quarterly (Exh. ES-RDP-1, at 34). According to the Companies, the proposed consolidation of rate classes will place all Rate G-1/Rate G-5 customers under the commercial six-month procurement, while the larger Rate G-2 through Rate G-4 classes will be subject to the quarterly industrial procurement (Exh. ES-RDP-1, at 34).

2. Positions of the Parties

a. RESA

As set forth above in Section IV.D.5.c.ii, the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time. As such, the current basic service procurement process will remain unchanged. Therefore, it is unnecessary to set forth much of RESA's arguments.

RESA argues that, despite the fact that the Companies' respective service territories cover different load zones, the revised rate design proposal would consolidate residential rate classes so that all residential customers across Massachusetts would have the same rates, but rate classes for C&I customers would remain separate between NSTAR Electric and WMECo (RESA Brief at 7, citing Exh. DPU-56-9, at 1 (Supp.), Procurement of Default Service, D.T.E. 02-40-A at 8-9 (2003); RESA Reply Brief at 3). RESA contends that the Companies' proposal is inconsistent with the Department's requirement that customers should be provided with appropriate price signals regarding the zonal cost differences associated with providing basic service, as established by the competitive market (RESA Brief at 7-8, citing D.T.E. 02-40-A at 10; Pricing and Procurement of Default Service, D.T.E. 99-60-A, at 3 (2003)).[98] Further, RESA argues that basic service prices that do not represent the actual cost of providing the service would inhibit the development of a competitive generation market and, therefore, would be detrimental to all electricity consumers (RESA Brief at 8-9, citing D.T.E. 99-60-A, at 3). According to RESA, impeding the competitive market is not in the public interest (RESA Brief at 9). Thus, RESA asserts that in order to maintain a "robust and properly functioning retail market" by ensuring that basic service rates align with prevailing market prices and are sending efficient price signals, the Department should reject the Companies' rate design proposal that results in the same rates for all residential customers across Massachusetts (RESA Brief at 9).

b. Companies

Eversource notes that it proposes to consolidate the Companies' energy procurement operations, but to continue to procure basic service based on the ISO-NE load zones in

98 According to RESA, the Department did not initially establish zone-differentiated basic service rates for residential and small commercial customers because the market lacked competitive options (RESA Brief at 8). However, RESA asserts that there is no longer a lack of competition in the market with over 20 licensed competitive suppliers serving residential and small commercial customers in Massachusetts (RESA Brief at 8, citing Massachusetts Department of Public Utilities, List of Licensed Suppliers (available at: http://webl.env.state.ma.us/DPU/FileRoom/Licenses)). Moreover, RESA adds that over one million residential customers are served by competitive suppliers (RESA Brief at 8, citing Massachusetts Department of Energy Resources, Electric Customer Migration Data (available at: http://www.mass.govieea/grants-and-tech-assistance/guidance-technical-assistance/agenciesand-divisions/doer/clectric-customer-migration-data.html)). Therefore, to maintain a competitive retail market, RESA argues that basic service rates should align with market prices and send efficient price signals (RESA Brief at 9).

eastern Massachusetts and western Massachusetts (Companies Brief at 12, citing Exh. ES-RDP-1, at 29, 34). The Companies do not specifically respond to RESA's arguments.

3. Analysis and Findings

Because the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time, the current basic service procurement process will remain unchanged. If the Companies seek to consolidate C&I rate classes in a future proceeding, they shall address any changes to distribution companies' costs, their billing systems, impacts to their customers, impacts to the suppliers, and the wholesale market in general. See D.T.E. 02-40-C at 20-22.

Further, we find that Eversource's proposal will not require all customers across the Commonwealth to pay the same rate for basic service. The Companies propose to maintain separate pricing between their NSTAR Electric and WMECo service territories and set basic service rates on the basis of separate ISO-NE zonal procurements (Exhs. ES-RDP-1, at 29, 34; CLC-1-3; CLC-9-1). Therefore, we are not persuaded by RESA's argument in this regard.

J. CIAC Carrying Charge for Interconnection

1. Introduction

In June 2016, the Internal Revenue Service ("IRS") issued Revenue Notice 2016-36, "Transfers of Property to Regulated Public Utilities by Electric Generators," which affects the tax treatment of transfers of property to a regulated public utility in connection with interconnection of a distributed generation facility to the transmission system (Exh. DPU-3, at 22; Tr. 9, at 1804-1808). Prior to Revenue Notice 2016-36, the IRS required distribution companies to include in their gross income the payment by a distributed generation facility to the distribution company for the cost of capital improvements and equipment associated with interconnecting the facility, referred to as contribution in aid of construction ("CIAC") (Exh. DPU-3, at 3-4). Revenue Notice 2016-36 provided a new safe harbor in which the transfer property associated with an interconnection of a distributed generation facility will not be treated as CIAC or give rise to gross income (Exh. DPU-3, at 10).

Revenue Notice 2016-36 modifies and supersedes Revenue Notice 88-129, 1988-2 C.B. 541; Revenue Notice 90-60, 1990-2 C.B. 345; and Revenue Notice 2001-82, 2001-2 C.B. 619 by permitting "a generator (such as a solar or wind farm) may contribute an intertie to a utility that qualifies under the new safe harbor even if the generator is interconnected with a distribution system, rather than a transmission system, if all the requirements [...] are met" (Exh. DPU-3, at 10-11). Revenue Notice 2016-36 notes five requirements for the safe harbor to apply including one stating that the generator may not purchase electricity from the utility unless the purchase satisfies the five-percent test, meaning that during the ten taxable years of the utility beginning with the year in which the interconnected distributed generation facility is placed into service, no more than five percent of the projected total power flows will flow to the generator (Exh. DPU-3, at 12-13).

When Eversource agrees to interconnect a distributed generation facility, it adds a CIAC carrying charge calculated as the net present value of the tax payments and tax deductions over the depreciable life of the asset, discounted at the Companies' weighted average cost of capital (Exh. NECEC-5-1; RR-DPU-27). Eversource seeks to continue to collect a CIAC carrying charge for all distributed generation facilities placed into service (Exh. NECEC-5-1). When a customer pays a CIAC, the amount of the CIAC must be included in Eversource's taxable income (Exh. NECEC-5-1). The Companies collect a CIAC carrying charge from customers that interconnect distributed generation because Eversource pays taxes to the IRS up front when the CIAC is received (Exh. NECEC-5-1). When the equipment associated with the interconnection and CIAC depreciates, it results in a deferred tax asset to insulate other customers from paying carrying charges associated with the increase in rate base resulting from Eversource's receipt of a CIAC (Exh. NECEC-5-1).

2. Positions of the Parties[99]

a. NECEC[100]

NECEC argues that IRS Revenue Notice 2016-36 establishes that, for many distributed generation interconnections, Eversource does not have federal tax liability, and thus should stop collecting a CIAC carrying charge from those distributed generation

[99] All references to the briefs in this section are to the briefs filed by the intervenors and Companies in July and August 2017.

[100] No other party commented on the CIAC carrying charge interconnection issue in this proceeding. However, the Department acknowledges receipt of detailed comments from Syncarpha Capital, LLC ("Syncarpha") (Syncarpha Comments at 2-18). Syncarpha, an installer of 14 solar distributed generation facilities in the Commonwealth, states that Eversource should not collect a tax gross-up amount from Syncarpha or any other interconnecting customer that satisfies the requirements of Revenue Notice 2016-36 (Syncarpha Comments at 2, 4). Further, Syncarpha requests that the Department require the Companies to refund tax gross-up payments paid by Syncarpha to Eversource during the past several years (Syncarpha Comments at 5).

facilities (NECEC Brief at 39 citing Exhs. DPU-3 at 10-11; NECEC-5-8; Tr. 9, at 1804-1809; RR-DPU-27). NECEC claims that the record shows that in 2016, Eversource collected approximately $3 million in CIAC carrying charges from customers who installed distributed generation facilities without equivalent tax liability (NECEC Brief at 38-39; NECEC Reply Brief at 8 citing Exh. NECEC-5-1). Further, NECEC maintains that Eversource did not provide comprehensive responses to NECEC's information requests concerning this CIAC carrying charge interconnection issue (NECEC Brief at 38-39). As such, NECEC asserts that it is unclear: (1) whether Eversource actually paid any taxes that would support the need to collect offsetting carrying charges from customers; (2) what Eversource does with the funds it collects through such charges prior to payment for tax liabilities; and (3) whether Eversource ever reconciles the amounts it collects with the amount it purports to pay in associated taxes (NECEC Brief at 40-41 citing Exhs. NECEC-5-2; NECEC-5-4; NECEC-5-5; NECEC-5-6; NECEC-5-7).

NECEC argues that it is particularly important to understand how Eversource has handled the CIAC carrying charges it has collected because, after Revenue Notice 2016-36, it should be possible for Eversource to obtain refunds associated with any tax payments made reflecting the receipt of interconnection costs (NECEC Brief at 41). Further, NECEC contends that collecting a CIAC carrying charge from customers who pay interconnection upgrade costs to interconnect distributed generation facilities creates a barrier to the deployment of distributed generation, which is contrary to the Commonwealth's public policy (NECEC Brief at 41). In addition, NECEC claims that to the extent electric distribution companies determine that they will not include the contributions of customers to interconnect as income for tax purposes, there is a need to ensure that the funds collected from customers are appropriately reimbursed (NECEC Brief at 41).

NECEC asserts that the Department should open a docket to investigate the practice of Eversource and the other electric distribution companies with respect to the collection of CIAC carrying charges from customers who pay to interconnect distributed generation resources to the electric grid (NECEC Brief at 3, 39; NECEC Reply Brief at 9). NECEC further asserts that, in the interim, the Department should direct Eversource to cease collecting CIAC carrying charges, document its past collection of such charges and the disposition of funds collected through such charges, and develop a mechanism for reimbursing its customers (NECEC Brief at 3, 39; NECEC Reply Brief at 9).

b. Companies

Eversource argues that it is "far from clear" that a blanket exemption from tax liability exists for interconnection charges (Companies Reply Brief at 145). In particular, Eversource notes that the IRS previously has issued letter rulings that are contrary to Revenue Notice 2016-36 (Exh. NECEC-5-8). In this regard, Eversource sent questions to the IRS to seek clarity on the contradiction and will apply the final decision accordingly (Exh. NECEC-5-8; RR-DPU-27). Eversource avers that it is collecting the CIAC carrying charges without a tax liability and that such fees are credited to all customers to insulate customers from the negative impact to rate base caused by including the CIAC in taxable income (Companies Reply Brief at 145 citing Exh. NECEC-5-1). The Companies assert that if they cease collecting the CIAC carrying charge from a few interconnecting customers prior to receiving IRS clarification, there would be an adverse impact to all other customers because they would experience an increase in rate base (Companies Reply Brief at 146). Further, Eversource claims that if the Department orders the Companies to refund the CIAC carrying charges already collected from interconnecting customers, all customers would see an increase in rates to account for the refund costs (Companies Reply Brief at 146).

3. Analysis and Findings

The Department has reviewed Revenue Notice 2016-36 and the alleged impacts of the continued collection of CIAC carrying charges that NECEC and Syncarpha raise (see n.100 above). Since Eversource did not clearly address this issue in its initial filing, the Department is concerned that other stakeholders, who are not parties to this proceeding, may not have had an opportunity to adequately consider and argue the interconnection CIAC carrying charge issue. In particular, the Department expects that project developers as well as the other electric distribution companies, could have an interest in collection of interconnection CIAC carrying charges and the interpretation of Revenue Notice 2016-36. However, a significant number of these stakeholders are not actively involved in this proceeding.[101]

As the agency that regulates the interconnection of distributed generation and approves associated tariffs, the Department has made significant efforts to ensure that the rules,

101 The Department notes that the other electric distribution companies, Fitchburg Gas and Electric Light Company and Massachusetts Electric Company and Nantucket Electric Company, are participating in this proceeding, but as limited participants.

regulations, and policies governing interconnection are applied in a consistent manner across the different electric distribution company service territories. See Interconnection of Distributed Generation, D.P.U. 11-75-A at 4-5 (2012) (convening a working group is appropriate for the purpose of reaching a consensus on interconnection of distributed generation issued). In keeping with this objective, we find that the possibility of an electric distribution company ceasing collection of CIAC carrying charges from customers who pay to interconnect distributed generation facilities warrants broader inquiry, with relevant input from interested stakeholders, to determine whether and to what extent a consistent and reasonable ratemaking approach may be developed.

Based on this finding, the Department concludes that it would be inefficient to expend additional resources on the adjudication of the interconnection CIAC carrying charge issue in the instant proceeding. See Eastern Energy Marketing, Inc. and Enserch Energy Services, Inc., D.P.U. 96-47, at 2 (1996) (Department finding it inefficient to develop and issue a policy statement and generic guidelines mandating the unbundling of gas services in light of specific proposals before it). Rather, the Department determines that it would be appropriate to open a proceeding in the future to investigate the tax treatment of CIAC carrying charges as applied to the interconnection of distributed generation facilities, with the intent to set a uniform practice for all electric distribution companies. Among other issues, we anticipate collecting data regarding the number of interconnected distributed generation facilities that would meet the requirements of Revenue Notice 2016-36, the impact to customers without distributed generation, and proposals for addressing any refunds that the Department may deem necessary. The Department expects to open a generic proceeding to establish a uniform policy regarding the tax treatment of CIAC carrying charges and make determinations as to whether electric distribution companies should: (1) have collected CIAC carrying charges; (2) issue refunds to interconnected customers; and (3) exclude such charges for future interconnecting customers.

The Department finds that reserving adjudication of the interconnection CIAC carrying charge issue for a subsequent proceeding is reasonable and necessary for a fair resolution of the issues presented. Further, we find that our decision will not impact adjudication of the Eversource's remaining proposals in the instant base rate case, which focus on the Companies' overall rate design. Further, we do not make findings with respect to the substance of the interconnection CIAC carrying charge issue and, therefore, nothing prevents the Companies or another entity from raising the issue at a later time. Based on the foregoing and without prejudice to the Companies or NECEC, the Department declines to reach the merits of the interconnection CIAC carrying charge issue at this time.

K. Rate-by-Rate Analysis

1. Introduction

The Department must determine, on a rate class by rate class basis, the proper level at which to set the customer charge and distribution charges for each rate class, based on a balancing of our rate design goals. The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. See, e.g., D.T.E. 02-24/25, at 256;

D.T.E. 01-56, at 139; D.P.U. 92-250, at 193-194; D.P.U. 92-210, at 214. This allocation method satisfies the Department's rate design goal of fairness. Nonetheless, the Department must balance its goals of fairness with its goal of continuity. For this balancing, we have reviewed the changes in total revenue requirements by rate class and bill impacts by consumption level within rate classes.[102]

In balancing our rate design goals, the Department seeks optimal economic efficiency. Overall, the Department seeks to achieve revenue adequacy and fair apportionment of costs while promoting economically justified use. However, there are factors and constraints that affect achieving an efficient balancing of our rate design goals. For example, some current utility rate structures, as is the case with NSTAR Electric, are based on dated rate structures adjudicated and established more than 25 years ago. For example, Boston Edison Company's rate structure was last adjudicated and established in 1986, Boston Edison Company,

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[102] In its initial rate design proposal, Eversource provided bill impacts for residential customers for 2018 and 2019 and for C&I customers for 2018 across a range of usage levels (Exhs. ES-RDP-2, Sch. RDP-9; ES-RDP-3, Sch. RDP-3). Moreover, in its revised rate design proposal, Eversource similarly provided bill impacts for residential customers for 2018 and 2019 and for C&I customers for 2018 across a range of usage levels (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-9; RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3). For C&I customer rates after 2018, ten models summarize bill impacts for the five proposed NSTAR Electric consolidated rate classifications (i.e., Rate G-1 non-demand, Rate G-1 demand, Rate G-2, Rate G-3 and Rate G-4), and for the five proposed WMECo aligned rate classifications (i.e., Rate G-1 non-demand, Rate G-1 demand, Rate G-2, Rate G-3 and Rate G-4) (Exhs. ES-RDP-1, at 62 n.15; ES-RDP-4, Schs. RDP-3 through RDP-7, RDP-11 through RDP-14 (East); ES-RDP-4, Schs. RDP-3 through RDP-7, RDP-12, and RDP-13 (West); RR-DPU-50, Att. (g)). According to Eversource, convergence of multiple rate designs to a single rate design results in disparate bill impacts from customer to customer as the impact of the rate designs are compounded by differences in customer load factor (Exh. ES-RDP-1, at 61).

D.P.U. 86-271 (1986); Commonwealth Electric Company's rate structure was last adjudicated and established in 1991, Commonwealth Electric Company, D.P.U. 89-117/90-331/91-80 (1991); and Cambridge Electric Light Company's rate structure was last adjudicated and established in 1993, Cambridge Electric Light Company, D.P.U. 92-250 (1993). These rate cases were followed by several rate settlements with little or no content pertaining to rate design. As a result, those legacy rate structures may have been designed under cost structures that no longer align with market economics. Remedying these aged cost structures presents challenges to our goal of continuity, meaning that rate structure changes should be made in a predictable and gradual manner, with limited, unexpected changes seriously adverse to existing customers, and that reasonable time should be allowed for consumers to adjust their consumption pattern in response to a change in the structure. Also, utility rate structures must account for federal and state energy initiatives (e.g., PURPA,[103] Massachusetts electric industry restructuring[104]), public policy actions (e.g., low-income discount, farm discount, system benefits charges, net metering), and changing market conditions. In establishing specific rate structures, the Department executes its assigned ratemaking function by applying our expertise and judgment in balancing the rate design goals in consideration of public policy requirements.

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[103] Public Utility Regulatory Policies Act of 1978, 92 Stat. 3117.

[104] An Act Relative to Restructuring the Electric Utility Industry In The Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein, St. 1994, c. 164.

In Section IV.D.5.c above, the Department directed the Companies to: (1) consolidate and align their residential rates and classes effective February 1, 2018; (2) maintain existing legacy C&I rate classes effective February 1, 2018; and (3) consolidate street lighting rates within NSTAR Electric and align street lighting rate class availability across NSTAR Electric and WMECo effective February 1, 2018. The Department did not allow the Companies to implement base distribution rate design changes effective January 1, 2019, as the Companies had proposed. Therefore, in the Department's rate by rate analysis, our findings pertain only to rates for effect on February 1, 2018.

2. Residential

a. Introduction

The Companies' current residential rates are available for all domestic purposes in individual private dwellings, individual apartments, or residential condominiums (M.D.T.E. No. 120F; M.D.T.E. No. 220G; M.D.T.E. No. 320F; M.D.P.U. No. 100W). For rates effective February 1, 2018, the Companies proposed to retain all existing residential rate classes (Exh. DPU-56-9, at 1 (Supp.); Motion to Delay Rate Implementation at 1-2). For rates effective January 1, 2019, the Companies proposed to consolidate rate classes and distribution rates for both NSTAR Electric and WMECo, so that within each rate class, all residential customers across Eversource's service territory would have the same rates (Exhs. DPU-56-9, at 1 (Supp.); ES-RDP-1, at 17-18; ES-RDP-9, at 27-28). Thus, the Companies proposed that the consolidated residential tariffs (i.e., Rate R-1 to Rate R-4) will govern residential customers served by NSTAR Electric and by WMECo (Exh. ES-RDP-9, at 26).

Eversource's proposed consolidated Rate R-1 is available for all domestic uses in a single private dwelling, in an individual apartment or in a residential condominium in which the principal means of heating the premises is not provided by permanently installed electric space heating equipment (RR-DPU-51, Att. (c) at 1). Eversource's proposed consolidated Rate R-2 is available to any Rate R-1 customer that is eligible for the low-income home energy assistance program, or its successor program, or receives any means-tested public benefit for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (RR-DPU-51, Att. (c) at 4).

Eversource's proposed consolidated Rate R-3 is available for all domestic uses in a single private dwelling, in an individual apartment, or in a residential condominium where the principal means of heating the premises is provided by permanently installed electric space heating equipment (RR-DPU-51, Att. (c) at 7). Eversource's proposed consolidated Rate R-4 is available to any Rate R-3 customer that is eligible for the low-income home energy assistance program, or its successor program, or receives any means-tested public benefit for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (RR-DPU-51, Att. (c) at 12). The Companies' proposed customer charges for 2018 are set forth in the tables below.

b. WMECo Residential

WMECo Residential Rates and Charges[105]

Current Rate Class	Proposed Rate Class	Availability	Current Customer Charge	2018 Proposed Customer Charge
R-1	R-1	Residential non-heating	$6.00	$8.00
R-2	R-2	Residential non-heating low income	$6.00	$8.00
R-3	R-3	Residential heating	$6.00	$8.00
R-4	R-4	Residential heating low income	$6.00	$8.00

The Companies proposed to eliminate WMECo's inclining block rates (Exh. ES-RDP-1, at 13). Eversource proposed to transfer all WMECo legacy Rate R-1 customers to consolidated Rate R-1, all WMECo legacy Rate R-2 customers to consolidated Rate R-2, all WMECo legacy Rate R-3 customers to consolidated Rate R-3, and all WMECo legacy Rate R-4 customers to consolidated Rate R-4 for rates effective January 1, 2019 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (West)).

105 Source: RR-DPU-50, at Exh. ES-RDP-3 (ALT1), Sch. RDP-1 (West).

c. Boston Edison Company Residential

Boston Edison Company Residential Rates and Charges[106]

Current Rate Class	Proposed Rate Class	Availability	Current Customer Charge	2018 Proposed Customer Charge
R-1	R-1	Residential non-heating	$6.43	$8.00
R-2	R-2/R-4	Residential heating and non-heating low income	$6.43	$8.00
R-3	R-3	Residential heating	$6.43	$8.00
R-4	R-1	Optional Residential Time of Use	$9.99	$9.99

Eversource proposed to transfer all Boston Edison Company legacy Rate R-1 and Rate R-4 customers to consolidated Rate R-1, and all Boston Edison Company legacy Rate R-3 customers to consolidated Rate R-3 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)). The Companies proposed to transfer Boston Edison Company legacy customers on Rate R-2 to consolidated Rate R-4 if these customers are low-income heating customers (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)). Eversource proposed to transfer non-heating customers on Boston Edison Company legacy Rate R-2 to consolidated Rate R-2 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)).

106 Source: RR-DPU-50, at Exh. ES-RDP-3 (ALT1), Sch. RDP-1 (East).

d. Cambridge Electric Light Company Residential

Cambridge Electric Light Company Residential Rates and Charges[107]

Current Rate Class	Proposed Rate Class	Availability	Current Customer Charge	2018 Proposed Customer Charge
R-1	R-1	Residential non-heating	$6.87	$8.00
R-2	R-2	Residential non-heating low income	$6.87	$8.00
R-3	R-3	Residential heating	$7.77	$8.00
R-4	R-4	Residential heating low income	$7.77	$8.00
R-5	R-1	Optional Residential Time-of-Use (for R-1)	$10.47	$10.47
R-6	R-3	Optional Residential Space Heating Time-of-Use (for R-3)	$11.37	$11.37

Eversource proposed to transfer all Cambridge Electric Light Company legacy Rate R-1 and Rate R-5 customers to consolidated Rate R-1 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)). Eversource proposed to transfer all Cambridge Electric Light Company legacy Rate R-3 and Rate R-6 customers to consolidated Rate R-3 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)). The Companies proposed to transfer all legacy customers taking service on Rate R-2 and Rate R-4 to the respective consolidated Rate R-2 and Rate R-4 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)).

107 Source: RR-DPU-50, at Exh. ES-RDP-3 (ALT1), Sch. RDP-1 (East).

e. Commonwealth Electric Company Residential

Commonwealth Electric Company Residential Rates and Charges[108]

Current Rate Class	Proposed Rate Class	Availability	Current Customer Charge	2018 proposed Customer Charge
R-1	R-1	Residential non-heating	$3.73	$8.00
R-2	R-2	Residential non-heating low income	$3.73	$8.00
R-3	R-3	Residential heating	$10.03	$10.03
R-4	R-4	Residential heating low income	$10.03	$10.03
R-5	R-1	Controlled Water Heating (closed)	n/a	n/a
R-6	R-1	Optional Residential Time-of-Use (for R-1)	$7.33	$8.00

Eversource proposed to transfer all Commonwealth Electric Company legacy Rate R-1, Rate R-5, and Rate R-6 customers to consolidated Rate R-1 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)). Eversource proposed to transfer all Rate R-2, Rate R-3, and Rate R-4 to the respective consolidated Rate R-2, Rate R-3, and Rate R-4 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)).

108 Source: RR-DPU-50, at Exh. ES-RDP-3 (ALT1), Sch. RDP-1 (East).

f. Positions of the Parties

i. Attorney General

The Attorney General asserts that it is unreasonable to have customers' bills change by more than 1.5 times the average increase and by less than 0.5 times the class average percentage increase given the amount of rate mitigation required for other classes (Attorney General Brief at 12, citing Exh. AG-SJR-1, at 23). The Attorney General maintains that it is important to evaluate the change in a customer charge with respect to the impact on a low-use residential customer because this charge is a more significant portion of that customer's bill, as much as 25 percent (Attorney General Reply Brief at 5, citing Exh. ES-RDP-2, Sch. RDP-9). Further, the Attorney General alleges that the customer charge for a low-use residential Commonwealth Electric Company customer will increase from 8.8 percent to 16.9 percent of the total bill under the Companies' 2018 initial rate design proposal (Attorney General Reply Brief at 5, citing Exh. ES-RDP-2, Sch. RDP-9). Accordingly, the Attorney General argues that the Companies' bill impacts are unreasonable and contravene the rate design principles of continuity and fairness (Attorney General Reply Brief at 5-6, citing Massachusetts-American Water Company, D.P.U. 95-118, at 174-175 (1996)). Therefore, the Attorney General asserts that the Department should reject the Companies' proposed rate design (Attorney General Brief at 14).

The Attorney General recommends that residential rates move toward a common customer charge, but that increases in the charge should be limited to no more than 1.5 times the class-average increase, and no less than 0.5 times the class-average increase (Attorney

General Brief at 17, <u>citing</u> Exh. AG-SJR-1, at 28-29, 34). According to the Attorney General, the residential per-kWh charges then should be set to collect the remaining revenue requirement (Attorney General Brief at 17). The Attorney General contends that this approach makes progress toward cost-based rate consolidation "in a manner that is consistent with well-established regulatory principles, such as gradualism and fairness" (Attorney General Brief at 17).

ii. <u>Acadia Center</u>

Acadia Center argues that high customer charges contravene the Department's rate design principles of efficiency and fairness, and public policy principles for low-income customer equity (Acadia Center Brief at 9). Acadia Center recommends that monthly customer charges should be set at the cost of keeping a customer connected to the electric grid plus the associated customer service costs (Acadia Center Brief at 10). Acadia Center notes that customer charges may be set lower, based on public policy considerations (Acadia Center Brief at 10, <u>citing</u> Exhs. AC-ML-3, at 8; AC-ML-4).

According to Acadia Center, the Companies' proposed $8.00 customer charge for the residential rate classes is too high and is not supported by any intervenor (Acadia Center Brief at 12). Acadia Center recommends that the Department obtain a more accurate assessment of customer-related costs (Acadia Center Brief at 13). Further, Acadia Center argues that the Department must consider Commonwealth Electric Company customers' bill impacts when setting a uniform residential customer charge across the Companies' service territories (Acadia Center Brief at 13). Acadia Center recommends that a customer charge of approximately $5.50 is appropriate because it is the same as National Grid's residential customer charge and corresponds to a customer weighted average for Eversource's current residential customer charges (Acadia Center Brief at 13, citing Exh. CLC-JFW-1, at 10; D.P.U. 15-155, at 475; Acadia Center Reply Brief at 2, 9).

iii. Cape Light Compact

Cape Light Compact argues that the Department should reject the Companies' customer charge proposal because it contravenes the Department's ratemaking principles of efficiency, fairness, and continuity (Cape Light Compact Brief at 32). Cape Light Compact disagrees with Eversource's position that moving the customer charge closer to the fully allocated cost of service bill per month promotes economic efficiency (Cape Light Compact Reply Brief at 9). Cape Light Compact asserts that the Companies' proposed customer charges contravene the Department's rate design principle of efficiency because the Companies did not reasonably explain how their proposal sends accurate price signals to customers (Cape Light Compact Brief at 35, citing Exh. ES-RDP-1, at 43).

Cape Light Compact maintains that a customer charge should reflect the marginal cost, not the embedded cost, to accurately reflect an efficient price (Cape Light Compact Brief at 35, citing Exh. CLC-JFW-1, at 8). Further, Cape Light Compact argues that a customer charge should be designed to include only minimum connection costs, or the cost to connect a customer who uses little to no energy, and is comparable to the average of Boston Edison Company's, Cambridge Electric Light Company's, and Commonwealth Electric Company's current Rate R-1 customer charge (Cape Light Compact Brief at 32, citing

Exh. CLC-JFW-1, at 9-10; Cape Light Compact Brief at 41, citing Exh. CLC-JFW-1, at 11; Cape Light Compact Brief at 35, citing Exh. CLC-JFW-1, at 9; Cape Light Compact Reply Brief at 9).[109] Therefore, Cape Light Compact maintains that because Eversource designed customer charges based on embedded costs and included more than the minimum connection costs, Eversource's proposed customer charges are overstated, send improper price signals to customers, weaken customers' control of their bills, and reduce incentives to maximize energy efficiency (Cape Light Compact Brief at 35-36, 38, citing Exh. CLC-JFW-1, at 18).

Further, Cape Light Compact argues that Eversource's customer charge proposal shifts recovery of costs from the volumetric rate to the customer charge, and, thus, contravenes the Department's fairness principle (Cape Light Compact Brief at 38, citing Exh. CLC-JFW-1, at 10). As a result of this shift in costs, Cape Light Compact argues that low-use customers would contribute a larger share of recovery of volumetric costs compared to the share of costs a high-use customer would contribute (Cape Light Compact Brief at 38, citing Exh. CLC-JFW-1, at 14-17). Moreover, according to Cape Light Compact, a customer charge is unavoidable, and, therefore, burdens low-use customers and benefits high-use customers (Cape Light Compact Brief at 29, citing Exh. ES-RDP-1, at 3). Therefore, Cape Light Compact asserts that higher customer charges diminish price signals for efficient consumption and shift cost responsibility to low-use customers (Cape Light Compact Brief

109 According to Cape Light Compact, minimum connection costs include service drops, meters, meter reading, and billing (Cape Light Compact Brief at 35, citing Exh. CLC-JFW-1, at 9).

at 31, citing Exhs. CLC-JFW-1, at 4; CLC-KFG-1, at 21; AC-ML-1, at 19; SREF-TW/MW-1, at 6; VS-NP-1, at 13).

Cape Light Compact also asserts that increasing a customer charge by more than double is not a gradual rate change and contravenes the Department's ratemaking principle of continuity (Cape Light Compact Brief at 40, citing Exh. CLC-JFW-1, at 11). According to Cape Light Compact, abrupt changes in customer charges do not allow customers to adjust their consumption patterns (Cape Light Compact Brief at 41).

Moreover, according to Cape Light Compact, Eversource has not proven that a cost shift would result from a lower customer charge after decoupling, and has failed to consider whether revenue decoupling would result in cost-shifting from other classes to residential customers (Cape Light Compact Brief at 40). Cape Light Compact adds that Eversource's argument that a cost shift would result from a lower customer charge after revenue decoupling is baseless, insincere, and unproven (Cape Light Compact Brief at 40).

Cape Light Compact argues that, despite Eversource's attempts to minimize the importance of increasing customer charges, the Department should give the residential customer charges due scrutiny (Cape Light Compact Reply Brief at 10). Cape Light Compact recommends that the Department adopt its proposal to set the customer charge for NSTAR Electric at the current average of the three current customer charges for Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company (Cape Light Compact Brief at 32). Alternatively, Cape Light Compact asserts that, if the Department does not approve the Companies' proposed consolidation, then the

Department should set customer charges at the current rate for Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company (Cape Light Compact Brief at 32 n.9; Cape Light Compact Brief at 41, citing Exh. CLC-JFW-1, at 11).

iv. Low Income Network

According to the Low Income Network, the Companies' proposed consolidated Rate R-4 proposal causes a pattern of increases and decreases over two years and, therefore, is burdensome to customers (Low Income Network Brief at 1, citing Tr. 16, at 3292). For example, the Low Income Network explains that the Companies' proposed increase to WMECo customers is an average of 3.4 percent over two years, but results in an increase of 5.8 percent in the first year (Low Income Network Brief at 2). The Low Income Network maintains that this increase is more than the average low-income household's grocery expenses for 1.5 weeks (Low Income Network Brief at 2, citing Tr. 16, at 3290-3291). Therefore, the Low Income Network requests that the Department direct Eversource to provide smoother bill impacts for low-income customers where these customers would otherwise experience a sequence of increases and decreases, or uneven increases (Low Income Network Brief at 2).

v. Companies

In response to Cape Light Compact's argument that the customer charge should be set based on marginal cost, and lower than the $8.00 proposed by the Companies, Eversource argues that marginal cost pricing for rate design is contrary to recent Department precedent (Companies Brief at 39). According to the Companies, they relied on the ACOSS to set customer charges, which they contend is a method consistent with the Department's policies on rate design (Companies Brief at 39). Thus, Eversource argues that it is not inappropriately shifting usage related costs from the energy charge to the customer charge (Companies Brief at 39). Therefore, the Companies assert that Cape Light Compact's position is incorrect that it is fair to minimize fixed cost recovery because Eversource recovers reductions in volumetric cost recovery caused by energy efficiency through revenue decoupling (Companies Brief at 39). The Companies acknowledge that revenue decoupling is intended to recover such shortfalls; however, the Companies maintain that decoupling does not preclude them from designing rates that are intended to reasonably collect their revenue targets (Companies Brief at 39). Accordingly, Eversource contends that the Department should not find it appropriate for revenue decoupling to replace distribution rate design (Companies Brief at 39).

Further, the Companies argue that the fully allocated customer charge is approximately \$10 to \$15 per bill per month and does not include system demand costs (Companies Reply Brief at 13, 21, citing Exh. ES-RDP-1, at 42). Therefore, the Companies proposed \$8.00 customer charge is less than the fully embedded cost (Companies Reply Brief at 21).

In response to the Attorney General's complaint about the Companies' proposal to increase the customer charge from \$3.73 to \$8.00 for Commonwealth Electric Company customers, the Companies allege that for customers in the 10^{th} percentile of usage, the monthly bill impact is only $4.34 (Companies Reply Brief at 13).[110] Eversource maintains that the $8.00 customer charge represents the cost that it incurs for administering a customer's bill and having service in place, and it does not over recover customer-related costs (Companies Reply Brief at 13, citing Exh. ES-RDP-1, at 43). According to the Companies, an $8.00 customer charge ensures that low-use customers pay a portion of actual customer-related costs, and therefore, are not subsidized by higher use customers in the same rate class (Companies Reply Brief at 13, citing Exh. ES-RDP-1, at 43). Therefore, the Companies disagree with the Attorney General's argument that the bill impact for an average-use customer is meaningless and that the Department should evaluate bill impacts only for low-use customers (Companies Reply Brief at 12).

In response to the Cape Light Compact's recommendation that the Companies average the proposed customer charges for the three legacy NSTAR Electric companies, Eversource asserts that this recommendation reduces the efficiency and fairness of the rate design (Companies Reply Brief at 21). Further, Eversource asserts that it has not suggested that the Department not scrutinize individual fixed charges, as suggested by Cape Light Compact (Companies Reply Brief at 21-22). Eversource clarifies that it supports bill impact analyses where a change in rates causing a large percentage increase but relatively small dollar increase, is not viewed as significant of an impact as one causing a large percentage and relatively large dollar increase (Companies Reply Brief at 22). Therefore, Eversource asserts

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110 A customer using approximately 0 kWh per month to 178 kWh per month is included in the 10th percentile of usage (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ATL1), Sch. RDP-9, at 12 (East)).

that its residential customer charge proposal balances total bill impacts for all customers and maintains fairness (Companies Reply Brief at 22). For all these reasons, the Companies maintain that their proposed customer charge for their residential rate classes is reasonable (Companies Reply Brief at 13).

g. Analysis and Findings

The Department approved the Companies' consolidation of residential rates above in Section IV.D.5.c.i. In approving the Companies' consolidation of residential rates, the Department allowed the Companies' to eliminate residential inclining block rates, residential seasonal rates, residential optional TOU rates, and residential controlled water heating rates. Therefore, based on our findings in Section IV.D.5.c.i above, for residential rates effective February 1, 2018, the Department directs Eversource to modify WMECo's volumetric charges so that these rate classes are charged based on a flat rate structure. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase.

Accordingly, effective February 1, 2018, the Department approves Eversource's residential rates to include the following rate schedules: (1) Rate R-1 Residential, for customers taking non-heating service at a residential premise; (2) Rate R-2 Residential Assistance, for customers taking non-heating service at a residential premise who qualify for identified means tested public benefits; (3) Rate R-3 Residential Heating, for customers taking electric space heating service at a residential premise; and (4) Rate R-4 Residential Assistance Heating, for customers taking electric space heating service at a residential premise who qualify for identified means tested public benefits (Exh. ES-RDP-1, at 20-21; RR-DPU-51, Att. (c) at 1-12).

According to the Companies' ACOSS, the embedded customer charge for the consolidated Rate R-1 and Rate R-2 is $10.88 per month (RR-DPU-49, Att. (J) at Exh. ES-ACOS-2 (ALT1) at 7). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $7.00 for Rate R-1 and Rate R-2 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs the Companies to set the volumetric charges for Rate R-1 and Rate R-2, truncated at five decimal places, to collect the remaining class revenue requirement approved in this Order. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

According to the Companies' ACOSS, the embedded customer charge for consolidated Rate R-3 and Rate R-4 is $13.89 per month (RR-DPU-49, Att. (J) at Exh. ES-ACOS-2 (ALT1) at 7). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a proposed monthly customer charge of $7.00 for Rate R-3 and Rate R-4 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs the Companies to set the volumetric charges for Rate R-3 and Rate R-4, truncated at five decimal places, to collect the remaining class revenue requirement approved in this Order. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

3. C&I

a. Introduction

NSTAR Electric's and WMECo's rate classifications include a variety of sized-based availability criteria (Exh. ES-RDP-1, at 51). Some rate classifications are available to customers with defined end uses, such as commercial space heating, all electric schools, and church service (Exh. ES-RDP-1, at 51-52). The Companies' current C&I rate classes also contain a variety in the rate structures, TOU periods, and definitions of billing demand (Exh. ES-RDP-1, at 52). In Section IV.D.5.c.ii above, the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time. Therefore, we shall address only changes to rates effective February 1, 2018. NSTAR Electric and WMECo's current C&I rate classes are listed in the table, below.

Legacy C&I Rate Classes[111]

Boston Edison Company	Cambridge Electric Light Company	Commonwealth Electric Company	WMECo
• General Service Rate G-1 (demand/non-demand) • General Service Rate G-2 • General Service TOU Rate G-3 • Opt. General Service TOU Rate T-1 • Opt. General Service TOU Rate T-2 • General Service Standby SB-G3 • General Service Standby SB-T2 • WR	• General (non-demand) Rate G-0 • General Rate G-1 • Large General TOU/Secondary Rate G-2 • Large General TOU / 13.8 kV Service Rate G-3 • Optional General TOU Rate G-4 • Commercial Space Heating Rate G-5 • Optional General TOU (non-demand) Rate G-6 • SB-1 • SB-G2 • SB-G3	• General Rate G-1 • Medium General Service TOU Rate G-2 • Large General Service TOU Rate G-3 • General Power Rate G-4 • Commercial Space Heating Rate G-5 • All Electric School Rate G-6 • Optional General TOU Rate G-7 • SB-G2 • SB-G3	• Small General Service TOU Rate T-0 • Large Primary Service Rate T-2 • Primary General Service Rate T-4 • Extra Large Primary Service TOU Rate T-5 • Small General Service Rate G-0 • Primary General Service Rate G-2 • Optional Church Rate 24 • Optional Controlled Water Heating Rate 23

b. Positions of the Parties

i. Attorney General

The Attorney General recommends no change in the legacy non-residential rate classes, due to the diverse number of non-residential rates, and the special characteristics of the customers served by those rates (Attorney General Brief at 16). Additionally, the Attorney General recommends moving each non-residential rate class closer to its cost of service by increasing each specific rate or charge by the same percentage as the required

111 Source: Exh. ES-RDP-1, at 53.

revenue increase for the legacy class (Attorney General Brief at 16-17, citing Exhs. AG-SJR-1, at 41; DPU-AG-1-7; AG-SJR-AS-1, at 6).

ii. Acadia Center

Acadia Center argues that the proposed customer charges for all of WMECo's aligned C&I rate classes and NSTAR Electric's aligned Rate G-3 and Rate G-4 are higher than the customer-related unit costs (Acadia Center Brief at 13, citing Exh. AC-ML-1, at 21 (table 1)). Therefore, Acadia Center maintains that the customer charges must be reduced (Acadia Center Brief at 13-14).

c. Analysis and Findings

i. Boston Edison Company

(A) Rate G-1/Rate T-1 Overview

Rate G-1 is available to C&I customers with maximum demand that does not exceed or is not estimated to exceed 10 kW in any billing month (M.D.T.E. No. 130F). The Companies install a demand meter for customers with either three-phase service or single-phase service exceeding 100 amperes (M.D.T.E. No. 130F). Eversource proposed to decrease the customer charge for Rate G-1 non-demand customers from $8.14 per month to $7.55 per month, and for Rate G-1 demand customers from $12.09 per month to $11.21 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 1-3 (East)).

Rate T-1 is available to C&I customers with maximum demand at or estimated to be below 10 kW in any billing month (M.D.T.E. No. 133F). The Companies install a demand meter for customers with use exceeding 3,000 kWh in any one month to evaluate whether the customer is eligible for transfer to Rate T-2 (M.D.T.E. No. 133F). Eversource proposed to decrease the customer charge for Rate T-1 customers from $10.13 per month to $9.40 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 18 (East)).

(B) Rate G-1/Rate T-1 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for combined Rate G-1 and Rate T-1 is $15.26 per month (RR-DPU-49, Att. (B) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds monthly customer charges of $8.00 for Rate G-1 non-demand, and $11.00 for Rate G-1 demand are reasonable and are consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-1, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $10.00 for Rate T-1 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs the

Company to set the volumetric charges for Rate T-1, truncated at five decimal places, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation. Moreover, the Department directed the Companies to close Rate T-1 to new customers effective February 1, 2018 in Section IV.G.1.c.

(C) Rate G-2/Rate T-2 Overview

Rate G-2 is available to C&I customers with service voltage less than 10,000 volts and with maximum demand equal to or greater than 10 kW but less than 200 kW in any billing month (M.D.T.E. No. 131F). Eversource proposed to decrease the customer charge for Rate G-2 customers from $18.19 per month to $17.66 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 5-9 (East)). For demand above 10 kW, the Companies proposed to decrease the monthly winter demand charge from $9.43 to $9.15, and the monthly summer demand charge from $20.22 to $19.63 (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 5-9 (East)).

Rate T-2 is available to C&I customers with service voltage less than 10,000 volts and with maximum demand equal to or greater than 10 kW in any billing month (M.D.T.E. No. 134F). The Companies proposed to decrease the customer charge from $27.77 per month to

$26.95 per month for Rate T-2 customers with demand between 0 kW per month and 150 kW per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 19 (East)). For Rate T-2 customers with demand between 150 kW per month and 300 kW per month, the Companies proposed to decrease the customer charge from $114.62 per month to $111.25 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 19 (East)). For Rate T-2 customers with demand between 300 kW per month and 1,000 kW per month, the Companies proposed to decrease the customer charge from $166.67 per month to $161.77 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 19 (East)). For Rate T-2 customers with demand greater than 1,000 kW per month, the Companies proposed to decrease the customer charge from $374.57 per month to $363.56 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 19 (East)). In addition, the Companies propose to decrease the monthly winter demand charge from $11.20 per kW to 10.87 per kW and the monthly summer demand charge from $19.65 per kW to $19.07 per kW (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 19 (East)).

(D) Rate G-2/Rate T-2 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for combined Rate G-2 and Rate T-2 is $35.33 per month (RR-DPU-49, Att. (B) at Exh. ES-ACOS-2 (ALT1), at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $18.00 for Rate G-2 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-2, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

Based on a review of the embedded costs and the bill impacts on customers, the Department finds that the following monthly customer charges to be reasonable and consistent with the Department's rate design goals: (1) $27.00 for Rate T-2 with demand between 0 kW and 150 kW per month; (2) $110.00 for Rate T-2 customers with demand between 150 kW and 300 kW per month; (3) $160.00 for Rate T-2 customers with demand between 300 kW and 1,000 kW per month; and (4) $360.00 for Rate T-2 customers with demand greater than 1,000 kW per month. Moreover, the Department directs the Companies to set the demand charges for Rate T-2, truncated at two decimal places, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(E) Rate G-3 Overview

Rate G-3 is available to C&I customers (1) with service voltage equal to or greater than 14,000 volts, and (2) if the customer furnishes, installs, owns, and maintains, at its expense, all associated protective devices, transformers, and other equipment that the Companies require (M.D.T.E. No. 132F). Eversource proposed to increase the customer charge for Rate G-3 customers from $237.07 per month to $251.55 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 10-17 (East)). The Companies proposed to increase the monthly winter demand charge from $8.59 to $9.11 and the monthly summer demand charge from $14.56 to $15.45 (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 10-17 (East)).

(F) Rate G-3 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-3 is $156.09 per month (RR-DPU-49, Att. (B) at Exh. ES-ACOS-2 (ALT1), at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $250.00 for Rate G-3 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the demand charges for Rate G-3, truncated at two decimal places, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9, at 28

(East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(G) Rate WR Overview

Service under Rate WR is available for electricity supplied and delivered in bulk to Massachusetts Water Resources Authority's ("MWRA") Deer Island Treatment Facility from NSTAR Electric's K Street Transmission Station (M.D.P.U. No. 135G). Rate WR pre-dates electric industry restructuring in Massachusetts;[112] after this restructuring, Rate WR was revised to unbundle the rate for separate supply and distribution charges (Exh. DPU-62-6). Eversource allocates only MWRA customer-related costs to Rate WR (Exh. DPU-62-6). The Companies proposed to decrease the monthly customer charge for Rate WR from $187.00 to $154.21 (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East), at 28).

(H) Rate WR Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate WR is $150.48 per month (RR-DPU-49, Att. (B) at Exh. ES-ACOS-2 (ALT1), at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a

[112] The Legislature instituted major restructuring of the electric industry in Massachusetts, effective March 1, 1998, that, among other things, provided for unbundled supply and delivery of electricity. An Act Relative to Restructuring the Electric Utility Industry In The Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein, St. 1994, c. 164.

monthly customer charge set at the embedded customer cost as a result of the Companies' compliance ACOSS for Rate WR is reasonable and is consistent with the Department's rate design goals. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

ii. Cambridge Electric Light Company

(A) Rate G-0/Rate G-1/Rate G-6 Overview

Rate G-0 is available to C&I customers with maximum demand at or estimated below 10 kW in any three consecutive billing months (M.D.T.E. No. 230G). Eversource proposed to increase the customer charge for Rate G-0 customers from $4.62 per month to $5.34 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 25 (East)).

Rate G-1 is available to C&I customers with maximum demand greater than 10 kW in any three consecutive billing months, but not greater than 100 kW in each twelve consecutive billing months (M.D.T.E. No. 231G). Eversource proposed to increase the customer charge for Rate G-1 customers from $7.32 per month to $8.46 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 26 (East)).

Rate G-6 is an optional TOU non-demand rate available to C&I customers with maximum demand at or less than 10 kW in any three consecutive billing months (M.D.T.E. No. 236G). Eversource proposed to increase the customer charge for Rate G-6 customers from $8.22 per month to $9.49 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 31 (East)).

(B) Rate G-0/Rate G-1/Rate G-6 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for combined Rate G-0, Rate G-1, and Rate G-6 is $17.49 per month (RR-DPU-49, Att. (D) at Exh. ES-ACOS-2 (ALT1), at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $5.00 for Rate G-0 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs the Companies to set the volumetric charges for Rate G-0, truncated at five decimal places, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing this rate (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $8.00 for Rate G-1 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-1, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $9.00 for Rate G-6 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric charges for Rate G-6, truncated at five decimal places, to collect the remaining class revenue requirement approved in this Order, using the proposed method for establishing these rates. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(C) Rate G-2 Overview

Rate G-2 is available to C&I customers with maximum demand greater than 100 kW per month for at least twelve consecutive billing months (M.D.T.E. No. 232G). Eversource proposed to increase the customer charge for Rate G-2 customers from $90.00 per month to

$103.96 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 27 (East)).

(D) Rate G-2 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-2 is $155.87 per month (RR-DPU-49, Att. (D) at Exh. ES-ACOS-2 (ALT1), at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $97.00 for Rate G-2 is reasonable. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-2, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(E) Rate G-3 Overview

Rate G-3 is available to C&I customers with maximum demand greater than 100 kW per month for at least twelve consecutive billing months with service supplied at approximately 13,800 volts (M.D.T.E. No. 233G). Eversource proposed to increase the customer charge for Rate G-3 customers from $90.00 per month to $103.96 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 28 (East)).

(F) Rate G-3 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-3 is $154.06 per month (RR-DPU-49, Att. (D) at Exh. ES-ACOS-2 (ALT1), at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $97.00 for Rate G-3 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-3, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(G) Rate G-4 Overview

Rate G-4 is an optional TOU rate class available to C&I customers with maximum demand equal to or less than 100 kW per month for at least twelve consecutive billing months (M.D.T.E. No. 234G). Eversource proposed to increase the customer charge for

Rate G-4 customers from $10.92 per month to $12.61 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 29 (East)).

(H) Rate G-4 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-4 is $142.73 per month (RR-DPU-49, Att. (D) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $12.00 for Rate G-4 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-4, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(I) Rate G-5 Overview

Rate G-5 is a commercial space heating rate that has been closed to new customers since December 1, 1985 (M.D.T.E. No. 235G). Eversource proposed to increase the customer charge for Rate G-5 customers from $7.20 per month to $8.32 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 30 (East)).

(J) Rate G-5 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-5 is $46.70 per month (RR-DPU-49, Att. (D) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $8.00 for Rate G-5 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric charges for Rate G-5, truncated at five decimal places to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

iii. Commonwealth Electric Company

(A) Rate G-1/Rate G-7 Overview

Rate G-1 is available to C&I customers with maximum demand less than or equal to 100 kW per month in each twelve consecutive billing months (M.D.T.E. No. 330F). Customers taking service on Rate G-1 can be classified as annual or seasonal customers (M.D.T.E. No. 330F). Eversource proposed to increase the customer charge for Rate G-1 annual and seasonal customers from $5.53 per month to $6.38 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 32-33 (East)).

Rate G-7 is an optional TOU rate that is available to C&I customers with maximum demand less than or equal to 100 kW per month in each twelve consecutive billing months (M.D.T.E. No. 336F). Customers taking service on Rate G-7 can be classified as annual or seasonal customers (M.D.T.E. No. 336F). Eversource proposed to increase the customer charge for Rate G-7 seasonal and annual customers from $9.13 per month to $10.54 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 39 (East)).

(B) Rate G-1/Rate G-7 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for combined Rate G-1 and Rate G-7 is $19.76 per month (RR-DPU-49, Att. (C) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $6.00 for Rate G-1 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-1 annual and seasonal, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $10.00 for Rate G-7 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs the Company to set the volumetric and demand charges for Rate G-7 annual and seasonal, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(C) Rate G-2 Overview

Rate G-2 is available to C&I customers with maximum demand greater than 100 kW per month but less than or equal to 500 kW per month in each twelve consecutive billing months (M.D.T.E. No. 331F). Eversource proposed to increase the customer charge for Rate G-2 customers from $360.13 per month to $416.40 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 34 (East)).

(D) Rate G-2 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-2 is $168.15 per month (RR-DPU-49, Att. (C) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $370.00 for Rate G-2 is reasonable. Moreover, the Department directs the Companies to set the volumetric and demand charges for Rate G-2, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(E) Rate G-3 Overview

Rate G-3 is available to C&I customers with maximum demand greater than 500 kW per month in each twelve consecutive billing months (M.D.T.E. No. 332F). Eversource proposed to increase the customer charge for Rate G-3 customers from $900.00 per month to $1,035.97 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 35 (East)).

(F) Rate G-3 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-3 is $158.42 per month (RR-DPU-49, Att. (C) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $930.00 for Rate G-3 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-3, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(G) Rate G-4 Overview

Rate G-4 is a general power service rate that has been closed to new customers since 1980 (M.D.T.E. No. 333F). Eversource proposed to increase the customer charge for Rate G-4 customers from $5.53 per month to $6.39 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 36 (East)).

(H) Rate G-4 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-4 is $59.79 per month (RR-DPU-49, Att. (C) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $6.00 for Rate G-4 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-4, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(I) Rate G-5 Overview

Rate G-5 is a commercial space heating rate class that has been closed to new customers since 1989 (M.D.T.E. No. 334F). Eversource proposed to increase the customer charge for Rate G-5 customers from $5.40 per month to $6.24 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 37 (East)).

(J) Rate G-5 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-5 is $27.88 per month (RR-DPU-49, Att. (C) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $6.00 for Rate G-5 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric charge for Rate G-5, truncated at five decimal places, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing this rate (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(K) Rate G-6 Overview

Rate G-6 is an all-electric school rate schedule that has been closed to new customers since 1980 (M.D.T.E. No. 335F). Eversource proposed to increase the customer charge for Rate G-6 customers from $27.13 per month to $31.34 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 38 (East)).

(L) Rate G-6 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate G-6 is $38.87 per month (RR-DPU-49, Att. (C) at Exh. ES-ACOS-2 (ALT1) at 4). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $30.00 for Rate G-6 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric charge for Rate G-6, truncated at five decimal places, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing this rate (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (East)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

iv. WMECo

(A) Rate 23 Overview

Rate R-23 is a closed rate for non-residential customers with separately metered water heaters (Exh. DPU-38-4; M.D.P.U. No. 1002W). According to the Companies, these accounts typically serve multi-unit buildings and have separate statements (Exh. DPU-38-4). The Companies proposed to increase the customer charge for Rate 23 customers from $16.00

per month to $21.04 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 1 (West)).

(B) Rate 23 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate 23 is $46.61 per month (RR-DPU-49, Att. (E) at Exh. ES-ACOS-2 (ALT1) at 3). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $17.00 for Rate 23 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric charge for Rate 23, truncated at five decimal places, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing this rate (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (West)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(C) Rate 24 Overview

Rate 24 is an optional rate for houses of worship (M.D.P.U. No. 1003W). This optional rate has been closed to new customers since 1992. D.P.U. 10-70, at 344-345. The Companies proposed to increase the customer charge for Rate 24 customers from $60.00 per month to $78.13 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 2 (West)).

(D) Rate 24 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate 24 is $133.72 per month (RR-DPU-49, Att. (E) at Exh. ES-ACOS-2 (ALT1) at 3). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $65.00 for Rate 24 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate 24, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (West)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(E) Rate G-0/Rate T-0 Overview

Rate G-0 is available to C&I customers with maximum demand at or below 349 kW per month (M.D.P.U. No. 1004W). The Companies proposed to increase the customer charge for Rate G-0 customers from $30.00 per month to $33.61 per month and the demand charge from $9.05 per kW to $10.14 per kW for all kWs over two kWs (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 3 (West)).

Rate T-0 is an optional TOU rate for C&I customers on Rate G-0 with demand at or below 349 kW per month (M.D.P.U. No. 1005W). The customer and demand charges are the same as Rate G-0, except that the demand charge is established based on demands only during the on-peak hours (i.e., 12:00 p.m. to 8:00 p.m.) (M.D.P.U. No. 1005W at 1; RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 3-4 (West)). The Companies proposed to increase the customer charge for Rate T-0 customers from $30.00 per month to $33.61 per month (Exhs. RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 4 (West)).

(F) Rate G-0/Rate T-0 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for the combined Rate G-0 and Rate T-0 is $28.90 per month (RR-DPU-49, Att. (E) at Exh. ES-ACOS-2 (ALT1) at 3). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $30.00 for Rate G-0 and Rate T-0 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-0 and Rate T-0, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (West)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(G) Rate G-2/Rate T-4 Overview

Rate G-2 is available to C&I customers with demand at or below 349 kW per month (M.D.P.U. No. 1006W). Customers taking service under Rate G-2 must take service at the primary level (M.D.P.U. No. 1006W). The Companies proposed to increase the customer charge for Rate G-2 customers from $325.00 per month to $436.24 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 5 (West)).

Rate T-4 is a TOU rate for C&I customers on Rate G-2 with demand at or below 349 kW per month (M.D.P.U. No. 1007W). The customer and demand charges are the same as Rate G-2, except that the demand charge is established based only on demands during the on-peak hours (i.e., 12:00 p.m.to 8:00 p.m.) (M.D.P.U. No. 1007W at 1; RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 5-6 (West); M.D.P.U. No. 1007W). The Companies proposed to increase the customer charge for Rate T-4 customers from $325.00 per month to $436.24 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 6 (West)).

(H) Rate G-2/Rate T-4 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for the combined Rate G-2 and Rate T-4 is $57.91 per month (RR-DPU-49, Att. (E) at Exh. ES-ACOS-2 (ALT1) at 3). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $353.00 for Rate G-2 and Rate T-4 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate G-2 and Rate T-4, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (West)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(I) Rate T-2 Overview

Rate T-2 is a TOU rate for C&I customers with monthly demand at or above 350 kW per month up to 2,500 kW per month (M.D.P.U. No. 1008W). The Companies proposed to increase to the customer charge from $700.00 per month to $980.20 per month for Rate T-2 customers with demand between 350 kW per month and 999 kW per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 7 (West)). For Rate T-2 customers with demand between 1,000 kW per month and 1,499 kW per month, the Companies proposed to increase the customer charge from $1,500.00 per month to $2,100.43 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 8 (West)). For Rate T-2 customers with demand between 1,500 kW per month and 2,500 kW per month, the Companies proposed to increase the customer charge from $2,500.00 per month to $3500.71 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Schs. RDP-1, at 2 (West); RDP-3, at 8 (West). In addition, Eversource proposed to increase the monthly demand charge for Rate T-2 from $6.31 per kW to $8.84 per kW (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 7-8 (West)).

(J) Rate T-2 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate T-2 $188.32 per month (RR-DPU-49, Att. (E) at Exh. ES-ACOS-2 (ALT1) at 3). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that monthly customer charges of: (1) $760.00 for customers with demand between 350 kW per month and 999 kW per month; (2) $1,625.00 for customers with demand between 1,000 kW per month and 1,499 kW per month; and (3) $2,700.00 for customers with demand between 1,500 kW per month and 2,999 kW per month for Rate T-2 are reasonable and are consistent with the Department's rate design goals. Moreover, the Department directs Eversource to set the volumetric and demand charges for Rate T-2, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (West)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to

Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

(K) Rate T-5 Overview

Rate T-5 is a TOU rate for C&I customers whose monthly demand is 2,500 kW per month and above (M.D.P.U. No. 1049B). The Companies proposed to increase the customer charge for Rate T-5 from $3,500.00 per month to $5,240.38 per month (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 9 (West)). The Companies proposed to increase the monthly demand charge for Rate T-5 from $4.49 per kW to $6.72 per kW (RR-DPU-50, Att. (f) at Exh. ES-RDP-3 (ALT1), Sch. RDP-3, at 9 (West)).

(L) Rate T-5 Analysis and Findings

According to the Companies' ACOSS, the embedded customer charge for Rate T-5 is $321.44 per month (RR-DPU-49, Att. (E) at Exh. ES-ACOS-2 (ALT1) at 3). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $3,800.00 for Rate T-5 is reasonable and is consistent with the Department's rate design goals. Moreover, the Department directs the Companies to set the volumetric and demand charges for Rate T-5, truncated at five decimal places and two decimal places, respectively, to collect the remaining class revenue requirement approved in this Order, using the Companies' proposed method for establishing these rates (RR-DPU-50, Att. (k) at Exh. ES-RDP-8 (ALT1), WP RDP-9 (West)). Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

4. Street Lighting

a. Introduction

Eversource offers street and security lighting service across all its service territories (Exh. ES-RDP-1, at 99). Street lighting refers to the lighting of roadways and security lighting refers to the use of area lights and flood lights in public and other outdoor spaces (Exh. ES-RDP-1, at 99).

The Companies currently offer two street lighting rate classes for all legacy companies in separate tariffs: (1) Rate S-1 for company-owned and maintained distribution poles, and company-owned and maintained luminaires; and (2) Rate S-2 for company-owned and maintained distribution poles and customer-owned and maintained luminaires (Exhs. ES-RDP-1, at 21; M.D.P.U. Nos. 140T, 240U, 241T, 340U, 341V, 1009AC, and 1010AC, and M.D.T.E. No. 141F). Additionally, Boston Edison Company has a separate provision for flood lighting, Rate S-3 (Exh. ES-RDP-9, at 31; M.D.P.U. No. 142T). The Companies proposed to consolidate Boston Edison Company's Rate S-3 into the proposed Rate S-1 (Exh. ES-RDP-9, at 31). Further, Eversource proposes to consolidate street lighting offerings within NSTAR Electric so that there is one Rate S-1 and one Rate S-2 for all NSTAR Electric legacy street lighting rate classes (Exh. ES-RDP-9, at 31; RR-DPU-51 Att. (c) at 32-47; proposed M.D.P.U. Nos. 511 and 512). Further, the Companies proposed to consolidate the tariffs between NSTAR Electric and WMECo but offer separate pricing between the two companies (Exh. ES-RDP-9, at 31; RR-DPU-51, Att. (c) at 32-47; proposed M.D.P.U. Nos. 511 and 512).

Additionally, the Companies proposed to introduce six new street lighting options for light-emitting diode ("LED") technology (Exh. ES-RDP-1, at 102-103). These offerings are contained within the Rate S-1 tariff and include LED fixtures ranging in load from 30 watts to 220 watts (Exh. ES-RDP-1, at 103).

The Companies initially proposed to align and consolidate street lighting rates effective January 1, 2018 (Exh. ES-RDP-1, at 50). In their revised rate design proposal, the Companies modified their initial rate design proposal so that aligned and consolidated street lighting rates would take effect January 1, 2019 (Exhs. DPU-56-9, at 1-2 (Supp.); ES-RDP-7 (ALT1), Schs. RDP-1 through RDP-9). In its revised proposal, Eversource proposed a transition period for 2018, in which street lighting rates would be maintained as they are currently offered (Exhs. DPU-56-9, at 1-2 (Supp.); ES-RDP-7 (ALT1), Schs. RDP-6 through RDP-9).

b. Positions of the Parties

i. DOER

DOER maintains that Eversource agreed to adopt a 25watt LED offering in its Rate S-1 tariff (DOER Brief at 16, citing Tr. 16, at 3285; DOER Reply Brief at 3, citing Tr. 16, at 3285). DOER recommends that the Department require the Companies to offer the lower wattage LED street lighting when evaluating the Companies' street lighting proposal for Rate S-1 (DOER Brief at 16; DOER Reply Brief at 3).

DOER notes that Eversource also acknowledged that: (1) the fixed charge per Rate S-1 customer would be lower if more fixtures were switched to lower-wattage equipment because demand costs would be lower; and (2) LED fixtures have longer life expectancies than non-LED fixtures, and, therefore, lower O&M costs (DOER Brief at 16, citing Exhs. DOER-1-5; DOER-1-6; DOER Brief at 17, citing RR-DOER-4; RR-DOER-5; Tr. 16, at 3286; DOER Reply Brief at 3). According to DOER, the Companies agreed that a separate, lower O&M cost for LED streetlights based on a 40-percent reduction to the O&M costs of traditional street lights is appropriate (DOER Brief at 17, citing Tr. 16, at 3286; DOER Reply Brief at 3, citing RR-DOER-4; RR-DOER-5; Tr. 16, at 3286). DOER asserts, however, the Companies proposed the same O&M costs regardless of the type of street lighting fixture in determining Rate S-1 rate design (DOER Brief at 16; DOER Reply Brief at 3-4). Therefore, DOER recommends that the Department direct the Companies to reduce the O&M costs for LED fixtures to reflect increased life expectancy and lower maintenance costs (DOER Brief at 17, 19, citing RR-DOER-4, Atts. (a)-(c); RR-DOER-5, Atts. (a)-(e); DOER Reply Brief at 4).

Further, DOER argues that the Companies' proposed street lighting rate structure for Rate S-2 discourages the deployment of energy efficient lighting (DOER Brief at 14). DOER asserts that the Companies' rate structure causes a municipality taking service on Rate S-1 using a 58-watt high-pressure sodium streetlight to pay less than a municipality taking service on Rate S-2 using a 30-watt LED fixture (DOER Brief at 17).

Additionally, DOER maintains that municipalities installing energy efficient lighting controls are unable to recover any savings in their electricity bills by reducing consumption, because the Companies' Rate S-2 tariff allows for an annual burn hour schedule based on the wattage of the fixture (DOER Brief at 18, citing Exhs. CAMB-SL-1; ES-RDP-12, Part 2, at 37; M.D.P.U. No. 512). Therefore, DOER supports Cambridge's request that the Department direct the Companies to develop a modified Rate S-2 tariff that reflects reduced billed usage caused by street lighting controls (DOER Brief at 18).

ii. Cambridge

Cambridge explains that it installed street lighting controls to operate almost all of its fixtures at 70 percent of maximum output in order to reduce usage for some street lights through scheduling their operation (Cambridge Brief at 5, citing Exh. CAMB-SL-1, at 2; Cambridge Reply Brief at 1). Cambridge alleges that the Companies' Rate S-2 tariff for customer-owned street lighting, however, does not recognize recued kWh usage as a result of lighting controls, because the tariff charges all unmetered street lights as if they operate at full output from dusk to dawn (Cambridge Brief at 5, citing RR-DPU-51, Att. (c) at 44; Cambridge Reply Brief at 1). Cambridge acknowledges that the full output from dusk to dawn may be appropriate for some street lights, but it is not appropriate for Cambridge's street lights (Cambridge Brief at 5). According to Cambridge, Eversource charged Cambridge for 2,073,917 kWh of usage in 2017, but the metered use for Cambridge's street lights was 891,784 kWh, or approximately 57 percent less (Cambridge Brief at 5; Cambridge Reply Brief at 1).[113] Therefore, Cambridge maintains that Eversource billed Cambridge $160,000 more that it would have been billed if Eversource billed street lights based on actual usage (Cambridge Brief at 6, citing Exh. CAMB-SL-1, at 3).

Moreover, Cambridge asserts that the Rate S-2 tariff does not meet the Department's rate design goal of efficiency (Cambridge Brief at 6). According to Cambridge, the Rate S-2 tariff does not provide a signal to customers to reduce consumption (Cambridge Brief at 6). Instead, Cambridge maintains that the Rate S-2 tariff charges customers based on a predetermined level of kWh, regardless of the actual amount of electricity the customer uses (Cambridge Brief at 6). Further, Cambridge alleges that the design of the Rate S-2 tariff does not provide an incentive for other municipalities to install street lighting controls to reduce electricity consumption and thereby energy costs (Cambridge Brief at 6, citing Exh. CAMB-SL-1, at 4).

Cambridge requests that the Department direct the Companies to work with Cambridge and other interested parties to develop a modified Rate S-2 tariff that reflects reduced billed usage caused by street lighting controls (Cambridge Brief at 6; Cambridge Reply Brief at 1-2). Cambridge recommends that, if the Department directs such action, Eversource file a report on its progress by March 1, 2018, with a modified tariff by June 30, 2018 (Cambridge Brief at 6; Cambridge Reply Brief at 1). Cambridge maintains that,

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113 Cambridge measured actual electricity usage with smart controllers on its street lights and claims that these devices contain revenue grade meters (Cambridge Brief at 5, citing Exh. CAMB-SL-1, at 2-3).

although Eversource agreed that a solution is necessary, Eversource did not endorse Cambridge's request for a working group claiming that it is "outside the scope of this proceeding" (Cambridge Reply Brief at 1). Cambridge asserts that this issue is within the scope of this proceeding because Eversource filed its street light tariff in this proceeding (Cambridge Reply Brief at 1).

iii. Acadia Center

According to Acadia Center, Cambridge's street lighting modernization is an action encouraged by statute, regulations, and state policy, but these policies are inconsistent with the Companies' proposal that billing for street lighting rates cannot vary based on actual usage (Acadia Center Reply Brief at 7, citing Cambridge Brief at 5; Companies Brief at 47). Acadia Center argues that the Department should establish a rate structure that rewards behaviors like Cambridge and encourages other cities to take similar actions (Acadia Center Reply Brief at 7). According to Acadia Center, modernizing the Companies' systems to accept information from technology other than meters is consistent with grid modernization efforts (Acadia Center Reply Brief at 7).

iv. Companies

(A) Response to DOER

The Companies assert that they proposed a 25-watt LED street light offering under Rate S-1 rate and a reduction of O&M costs for LEDs that reflect a longer life expectancy and lower maintenance costs (Companies Reply Brief at 33-34). According to the Companies' analysis, 59 percent of O&M costs are attributable to re-lamping, which is not a requirement for LED lighting (Companies Reply Brief at 34). Therefore, Eversource claims that it would be reasonable to apply 41 percent of the O&M component in its proposed street lighting rates to the design of the proposed LED street lighting rates (Companies Reply Brief at 34). The Companies maintain that they will re-evaluate LED O&M costs based on the actual O&M expense that they incur when setting LED street lighting rates in the future (Companies Reply Brief at 34).

(B) <u>Response to Acadia Center and Cambridge</u>

The Companies maintain that Cambridge installed street lighting controls knowing that Cambridge took service on the Companies' unmetered streetlight rates, and its bill would be unaffected (Companies Brief at 47). Eversource asserts that if Cambridge wanted to be billed according to a metered rate to reflect its controlled usage, it could have elected to take this service (Companies Brief at 47). The Companies note that municipalities traditionally do not elect metering for street lights because it is cost prohibitive (Companies Brief at 47).

The Companies maintain that Cambridge's metering systems do not interface with the Companies' billing system, and that the Companies cannot verify the accuracy of Cambridge's billing data (Companies Brief at 47). Eversource agrees with Cambridge that a solution is necessary and expects to allow meter reads from Cambridge's systems (Companies Brief at 47). However, Eversource states that it needs to develop procedures for accepting Cambridge's data (Companies Brief at 47). Therefore, the Companies maintain that the Department cannot address, in this proceeding, the issue of rewarding municipalities for installing more efficient fixtures because substantial evidence is not on the record (Companies

Reply Brief at 31). Eversource commits to investigating this issue and supports the formation of a working group with municipalities, including Cambridge, to resolve issues regarding the measurement of street lighting usage data (Companies Reply Brief at 31-32, 48). Moreover, Companies add that their LED street lighting proposal facilitates the deployment of energy efficient lighting and serves as a foundation to address these issues in the future (Companies Reply Brief at 32).

c. Analysis and Findings

In Section IV.D.5.c.iii above, the Department allowed the consolidation and alignment of the Companies' street lighting tariffs for rates effective February 1, 2018. Eversource has proposed a variety of changes to its street lighting service. The Department has examined the proposed rate design for the street lighting Rate S-1 and Rate S-2 (Exh. ES-RDP-7 (ALT1), Schs. RDP-1 through RDP-5). The Department finds that the proposed rate design for the street lighting rate classes satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the increase. Therefore, the Department directs Eversource in the compliance filing to compute the street light charges using the method proposed by the Companies, subject to our findings, and the increase from the allocation process and revenue requirement for the street light class approved by the Department. Further, with respect to Section 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation.

Regarding DOER's recommendations that the Eversource offer certain lower-wattage LED fixtures, the Companies agreed to accept DOER's recommendation to offer a 25-watt LED fixture (Companies Reply Brief at 33-34; Exh. DOER-6-2, Att.; Tr. 16, at 3285). Accordingly, the Department directs Eversource to include an offering in its street lighting tariff for a 25-watt LED rate.

Further, the Companies agreed to modify their O&M cost calculations used to determine their proposed LED lighting rates from its initial filing (Companies Reply Brief at 34; RR-DOER-5). The Department accepts the Companies' proposal to apply 41 percent of the O&M component of their street lighting rates to the design of their LED street light offerings. The Department finds this modification to be cost-based and, therefore, reasonable (RR-DOER-5). Therefore, the Department directs the Companies in their compliance filing to compute the rate for the LED lighting option using the revised method put forth by DOER and agreed upon by Eversource.

Regarding Cambridge's request for the Companies to work with Cambridge, and other interested parties, to develop a modified Rate S-2 tariff that reflects reduced billed usage caused by street lighting controls, Eversource stated that it does not oppose the formation of a working group to resolve issues related to measuring street light usage data (Cambridge Brief at 6; Cambridge Reply Brief at 1-2; Companies Reply Brief at 48). Accordingly, the Department directs Eversource to provide the Department, within 120 days of this Order, a report detailing the Companies' efforts to establish a working group with interested parties, and the groups' progress on reaching a solution to measuring street light usage data.

5. Standby Rate Tariffs (Rate SB-G2, Rate SB-G3, Rate SB-T2)

a. Introduction

In 2004, the Department approved the basic provisions of NSTAR Electric's current standby rate tariffs as a result of a settlement. NSTAR Electric Company, D.T.E. 03-121 (2004). In 2013, the Department approved modifications to the availability of these standby rate tariffs where existing standby rate customers, to the extent that they are eligible for service under the respective tariffs, could either (a) switch to the general service rate tariff or (b) voluntarily continue service under the standby rate tariffs to the extent that they are eligible. NSTAR Electric Company, D.P.U. 12-87 (3013).

Generally, standby rates are intended to provide a customer with a firm supply of electric power and energy when the customer's generating facility (typically, a distributed generation facility) is not in operation or not operating at full capability. D.T.E. 03-121, at 1 & n.5; Distributed Generation, D.T.E. 02-38, at 4 (2002).

NSTAR Electric currently has three groups of standby rates: Rate SB-G2, Rate SB-G3, and Rate SB-T2. D.P.U. 12-87, at 2.[114] Of these three groups of standby rates, Boston Edison Company offers service under Rate SB-G3 (M.D.P.U. No. 136E) and Rate SB-T2 (M.D.P.U. No. 138D); Cambridge Electric Light Company offers service under Rate SB-G2 (M.D.P.U. No. 254F) and Rate SB-G3 (M.D.P.U. No. 255F); and

114 Additionally, only Cambridge Electric Light Company has Rate SB-1 (13.8 kV), and it is closed to new customers (M.D.T.E. No. 237H). Standby service on Rate SB-1 is provided to customers with an alternative power source that exceeds 100 kilowatts and that supplies at least 20 percent of the customer's total integrated electrical load (M.D.T.E. No. 237H at 1).

Commonwealth Electric Company offers service under Rate SB-G2 (M.D.P.U. No. 338E) and Rate SB-G3 (M.D.P.U. No. 337E) (see also RR-DPU-51, Att. (a) at 371-376, 377-382, 463-469, 470-476, 519-524, and 525-530). Service under these tariffs is available to customers who qualify for general delivery service under legacy Rate G-2, Rate G-3, or Rate T-2, respectively, and who execute a standby service agreement with NSTAR Electric (M.D.P.U. Nos. 136E at 1; 138D at 1; 254 F at 1; 255F at 1; 337E at 1; 338E at 1; see also RR-DPU-51, Att. (a) at 371, 377, 463, 470, 519, and 525). More specifically, NSTAR Electric's standby rates are applicable to distributed generation customers with on-site facilities and with a nameplate capacity of either 1,000 kW or greater; or 250 kW or greater, if that facility will provide at least 30 percent of the customer's maximum internal electric load (M.D.P.U. Nos. 136E at 1; 138D at 1; 254 F at 1; 255F at 1; 337E at 1; 338E at 1; see also RR-DPU-51, Att. (a) at 371, 377, 463, 470, 519, and 525). No customers currently take service on Boston Edison Company's Rate SB-T2, Cambridge Electric Light Company's Rate SB-G2, and Commonwealth Electric Company's Rate SB-G2 and Rate SB-G3 (Exhs. DPU-15-1, Att. (a) at 3; DPU-59-33; DPU-59-34; DPU-59-35).

In this proceeding, the Companies proposed to transfer their standby rate customers to aligned Rate G-4 for effect January 1, 2019 (RR-DPU-50, Att. (e) at Exh. ES-RDP-2 (ALT1), Sch. RDP-2 (East)). In Section IV.D.5.c.ii above, the Department declined to approve Eversource's proposal to align and consolidate C&I rate classes at this time. Accordingly, in this section, the Department considers the existing legacy standby rate tariffs, to which the Companies propose no substantive changes (Exh. ES-RDP-14, (Part 1) at 32-46, 93-107, 140-153).

b. Positions of the Parties

i. TEC

TEC states that standby rates currently reflect a significant discount to standard rates, fostering the Department's and other policymakers' goal of promoting cogeneration (TEC Brief at 16, citing Tr. 17, at 3427). TEC notes that pursuant to the settlement agreement in D.P.U. 05-85, standby rates have been frozen, and, as a result, the gap between standby rates and corresponding standard distribution rates has continually widened (TEC Brief at 17, citing Tr. 17, at 3425). TEC asserts that any standby rate customers migrating to the Companies' proposed distribution rates would experience rate shock (TEC Brief at 17, citing Tr. 17, at 3429).

ii. Companies

The Companies maintain that standby rates, such as Rate SB-G3 and Rate SB-G2, are not based on a separate cost allocation (Companies Reply Brief at 41). According to Eversource, these rates are offshoots of the other applicable rate classes (i.e., Rate G-3 and Rate G-2) (Companies Reply Brief at 41).

c. Analysis and Findings

In D.P.U. 10-170-B, the Department approved a settlement agreement among: (1) NSTAR Electric and NSTAR Gas Company, along with their parent holding company, NSTAR; (2) WMECo, along with its parent holding company Northeast Utilities; and

(3) DOER ("DOER Settlement"). Article 2.7 of the DOER Settlement required NSTAR Electric to petition the Department to open a docket to review its standby rate tariffs with the goal of phasing out Rate SB-G2, Rate SB-G3, and Rate SB-T2 on a revenue neutral basis. DOER Settlement at Art. 2.7; D.P.U. 10-170-B at 91.[115] The DOER Settlement did not address Rate SB-1. In D.P.U. 12-87, the Department determined that NSTAR Electric's proposed standby rate tariffs required no further investigation at that time and that NSTAR Electric's filing complied with Article 2.7. D.P.U. 12-87, at 11-12. Moreover, regarding the possible phase out of the standby rates, the Department determined that nothing in Article 2.7 prevented the standby rate tariffs from remaining open to customers until the Companies' next base rate case. D.P.U. 12-87, at 11-12. During this time, Rate SB-G2, Rate SB-G3, and Rate SB-T2 remained open to NSTAR Electric's customers that were eligible for standby rates were allowed to take service under a rate tariff that is more advantageous to them. D.P.U. 12-87, at 12.

Given the Department's findings on the Companies' C&I rate design in Section IV.D.5.c.ii above to retain legacy rate classes for C&I customers in the immediate future, the Department must consider the appropriateness of retaining standby rate tariffs in light of our

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115 Specifically, Article 2.7, in pertinent part, provides as follows:

> Phase-out of Stand-by Rate Tariffs: The Settling Parties agree that, no later than six months from the date of the merger closing, NSTAR Electric shall petition the Department to open a docket to … review NSTAR Electric's stand-by rate tariffs with the goal of phasing out SB-G2 and SB-G3 tariffs on a revenue neutral basis as determined by the Department…

prior directives in D.P.U. 12-87. The Department has reviewed the proposed standby tariffs (RR-DPU-51, Att. (a) at 371-382, 436-440, 463-476, 519-530). No customers currently take service on Boston Edison Rate SB-T2, Cambridge Electric Light Rate SB-G2, and Commonwealth Electric Rate SB-G2 or Rate SB-G3 (Exhs. DPU-15-1, Att. (a) at 3; DPU-59-33; DPU-59-34; DPU-59-35).[116] Accordingly, the Department directs Eversource to cancel, effective February 1, 2018, M.D.P.U. No. 138D (Boston Edison Company Rate SB-T2), M.D.P.U. No. 254F (Cambridge Electric Light Company Rate SB-G2), M.D.P.U. No. 338E (Commonwealth Electric Company Rate SB-G2), and M.D.P.U. No. 337E (Commonwealth Electric Company Rate SB-G3).

Moreover, there is one customer taking service on Boston Edison Company Rate SB-G3, and there are two customers taking service on Cambridge Electric Light Company Rate SB-G3 (Exh. DPU-15-1, Att. (a) at 3). Since at least 2012, customers taking service on Boston Edison Company and Cambridge Electric Light Company Rate SB-G3 have been aware that the standby rate tariff would eventually phase out and no longer would be available as an option to take service. D.P.U. 10-170-B at 91. Further, in testimony filed in docket D.P.U. 12-87, dated October 10, 2012, the Companies stated that they would propose to cancel Rate SB-G2, Rate SB-T2, and Rate SB-G3 tariffs in the context of their next base rate proceeding. D.P.U. 12-87, Exh. NSTAR-RDC at 8. Accordingly, there has been regulatory certainty regarding the eventual elimination of standby rates.

[116] The Companies have not provided service to any customers on Commonwealth Electric Rate SB-G3 since 2013 (Exh. DPU-15-1, Att. (c) at 3).

The first availability provision for customers taking service on Rate SB-G3 is that the customer qualifies for service on Boston Edison Company or Cambridge Electric Light Company Rate G-3, based upon their internal electric load requirements, but instead chooses to take service under the standby rate tariff, rather than the applicable legacy Rate G-3. (RR-DPU-51, Att. (a) at 371, 470). Accordingly, the Department directs the Companies to close Boston Edison Company and Cambridge Electric Light Company Rate SB-G3 to new customers effective February 1, 2018 (RR-DPU-51, Att. (a) at 371-376, 470-476; proposed M.D.P.U. No. 136F; proposed M.D.P.U. No. 255G). Moreover, in order to allow for a reasonable transition for customers, the Department finds that it is appropriate to cancel these tariffs as of January 1, 2019. We direct the Companies to transfer any customers taking service at that time on Boston Edison Company Rate SB-G3 or Cambridge Electric Light Company Rate SB-G3 to the otherwise applicable Boston Edison Company or Cambridge Electric Light Company Rate G-3. See D.P.U. 10-70, at 356-357.

6. Conclusion

The Department directs Eversource to comply with the above directives regarding rate design for its residential, C&I, and street lighting rate classes in its compliance filing. Further, the Department allows the Companies' proposed Rate SB-1, Rate MS-1, and Rate SS-1 for effect February 1, 2018 (RR-DPU-51, Att. (a) at 436-450).

Additionally, the Companies proposed to eliminate WMECo's transitory demand rider, M.D.T.E. No. 1019B (Exh. ES-RDP-9, at 36). No party opposed the Companies' proposed elimination of WMECo's transitory demand rider. The Department finds it reasonable to eliminate WMECo's transitory demand rider, M.D.T.E. No. 1019B.

Eversource is directed to file revised tariffs with its compliance filing consistent with the directives above.

L. Schedule 10 – Allocation to Rate Classes - For illustrative purposes only

RATE CLASS	PRO FORMA BASE DISTRIBUTION REVENUE @ CURRENT RATES	PRO FORMA TOTAL REVENUE @ CURRENT RATES	RECONCILING RATE ADJUSTMENTS	PROPOSED BASE REVENUE AT EROR	PROPOSED ALLOCATION OF BASE REVENUE AT EROR	REVENUES CREDITED TO BASE RATES	PROPOSED REVENUE INCREASE AT EROR	10% REVENUE INCREASE CAP	PROPOSED REVENUE TO BE REALLOCATED 10% CAP ITERATION 1	BASE RATE REVENUE ALLOCATOR	PROPOSED REVENUE REALLOCATION PER 10% CAP ITERATION 1	PROPOSED REVENUE INCREASE AFTER REVENUE REALLOCATION PER 10% CAP ITERATION 1
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Residential (R-1 and R-2)	$ 390,568,779	$ 1,469,335,495	$ 36,465,006	$ 446,904,549	$ 436,443,366	$ 12,953,623	$ 69,385,970	$ 146,933,549	$ -	$ 436,443,366	$ 5,829,131	$ 75,215,101
Residential (R-3 and R-4)	$ 43,426,667	$ 184,609,623	$ 5,180,954	$ 63,918,617	$ 68,438,506	$ 1,895,466	$ 28,297,327	$ 18,460,962	$ 9,836,365	$ -	$ -	$ 18,460,962
EMA G1/T1 BOS	$ 34,243,264	$ 106,576,755	$ 642,509	$ 27,368,628	$ 27,699,313	$ 722,026	$ (6,623,468)	$ 10,657,676	$ -	$ 27,699,313	$ 369,952	$ (6,253,516)
EMA G2/T2 BOS	$ 267,822,356	$ 1,133,056,639	$ 20,012,381	$ 221,867,215	$ 224,547,957	$ 5,853,194	$ (29,115,212)	$ 113,305,664	$ -	$ 224,547,957	$ 2,999,059	$ (26,116,153)
EMA G3/SBG3/WR BOS	$ 75,923,008	$ 478,724,937	$ 6,945,391	$ 68,973,796	$ 69,807,182	$ 1,819,633	$ (990,069)	$ 47,872,494	$ -	$ 69,807,182	$ 932,344	$ (57,725)
EMA G0/G1/G6 CAM	$ 7,867,097	$ 42,631,245	$ (234,124)	$ 9,028,284	$ 9,137,370	$ 238,180	$ 797,968	$ 4,263,124	$ -	$ 9,137,370	$ 122,039	$ 920,007
EMA G2 CAM	$ 12,612,241	$ 83,373,541	$ (674,766)	$ 16,998,743	$ 17,204,133	$ 448,453	$ 3,468,673	$ 8,337,354	$ -	$ 17,204,133	$ 229,778	$ 3,698,451
EMA G3/SB1/SBG3 CAM	$ 8,127,064	$ 84,263,534	$ 1,895,472	$ 15,222,519	$ 15,406,447	$ 401,593	$ 8,773,262	$ 8,426,353	$ 346,909	$ -	$ -	$ 8,426,353
EMA G4 CAM	$ 114,880	$ 853,165	$ 8,711	$ 190,425	$ 192,726	$ 5,024	$ 81,533	$ 85,316	$ -	$ 192,726	$ 2,574	$ 84,107
EMA G5 CAM	$ 167,418	$ 1,256,863	$ (22,456)	$ 474,867	$ 480,604	$ 12,528	$ 278,203	$ 125,686	$ 152,517	$ -	$ -	$ 125,686
EMA G1/G7 COM	$ 37,310,195	$ 189,067,878	$ (2,238,675)	$ 48,673,049	$ 49,261,148	$ 1,284,069	$ 8,428,209	$ 18,906,788	$ -	$ 49,261,148	$ 657,931	$ 9,086,140
EMA G2 COM	$ 10,347,360	$ 69,382,782	$ (1,735,019)	$ 14,736,503	$ 14,914,559	$ 388,771	$ 2,443,409	$ 6,938,278	$ -	$ 14,914,559	$ 199,199	$ 2,642,607
EMA G3 COM	$ 5,772,597	$ 55,709,854	$ (1,768,325)	$ 9,819,385	$ 9,938,029	$ 259,050	$ 2,138,057	$ 5,570,985	$ -	$ 9,938,029	$ 132,732	$ 2,270,789
EMA G4 COM	$ 74,673	$ 403,004	$ (727)	$ 121,531	$ 122,999	$ 3,206	$ 44,393	$ 40,300	$ 4,093	$ -	$ -	$ 40,300
EMA G5 COM	$ 503,812	$ 2,310,407	$ 61,161	$ 1,040,152	$ 1,052,720	$ 27,441	$ 582,628	$ 231,041	$ 351,587	$ -	$ -	$ 231,041
EMA G6 COM	$ 71,426	$ 664,046	$ 6,267	$ 219,195	$ 221,843	$ 5,783	$ 150,901	$ 66,405	$ 84,497	$ -	$ -	$ 66,405
WMA Optional Water Heating 23	$ 8,999	$ 31,972	$ 90	$ 21,584	$ 21,845	$ 569	$ 12,366	$ 3,197	$ 9,169	$ -	$ -	$ 3,197
WMA Optional Church 24	$ 334,298	$ 1,143,200	$ 3,257	$ 696,388	$ 704,802	$ 18,372	$ 355,389	$ 114,320	$ 241,069	$ -	$ -	$ 114,320
WMA G-0/T-0	$ 24,579,853	$ 102,068,294	$ 310,496	$ 26,311,918	$ 26,629,835	$ 694,148	$ 1,666,330	$ 10,206,829	$ -	$ 26,629,835	$ 355,668	$ 2,021,997
WMA G-2/T-4	$ 11,001,556	$ 60,154,422	$ 7,923	$ 13,342,205	$ 13,503,414	$ 351,988	$ 2,157,794	$ 6,015,442	$ -	$ 13,503,414	$ 180,351	$ 2,338,145
WMA T-2	$ 14,188,285	$ 100,725,237	$ 502,692	$ 19,329,456	$ 19,563,007	$ 509,940	$ 5,367,474	$ 10,072,524	$ -	$ 19,563,007	$ 261,283	$ 5,628,757
WMA T-5	$ 4,730,539	$ 54,838,886	$ 90,793	$ 7,086,027	$ 7,171,645	$ 186,940	$ 2,344,959	$ 5,483,889	$ -	$ 7,171,645	$ 95,784	$ 2,440,743
Street Lighting S-1/S-2 EMA	$ 6,074,172	$ 19,115,438	$ 133,356	$ 7,776,548	$ 8,119,068	$ 150,935	$ 2,027,317	$ 1,911,544	$ 115,773	$ -	$ -	$ 1,911,544
Street Lighting S-1/S-2 WMA	$ 4,686,497	$ 8,262,484	$ (117,294)	$ 7,410,901	$ 6,949,964	$ 94,078	$ 2,052,095	$ 826,248	$ 1,225,846	$ -	$ -	$ 826,248
Total Company	$ 960,557,041	$ 4,248,559,700	$ 65,475,075	$ 1,027,532,485	$ 1,027,532,485	$ 28,325,010	$ 104,125,509	$ 424,855,970	$ 12,367,826	$ 926,013,685	$ 12,367,826	$ 104,125,509

RATE CLASS	PROPOSED BASE REVENUES OVER 200% CAP ITERATION 1	BASE RATE REVENUE ALLOCATOR	PROPOSED REVENUE ALLOCATION PER 200% CAP ITERATION 1	PROPOSED REVENUE INCREASE AFTER REVENUE ALLOCATION PER 200% CAP ITERATION 1	PROPOSED BASE REVENUES OVER 200% CAP ITERATION 2	BASE RATE REVENUE ALLOCATOR	PROPOSED REVENUE ALLOCATION PER 200% CAP ITERATION 2	PROPOSED REVENUE INCREASE AFTER REVENUE ALLOCATION PER 200% CAP ITERATION 2	PROPOSED BASE REVENUE INCREASE	PROPOSED BASE REVENUE REQUIREMENT	PROPOSED DISTRIBUTION PERCENT INCREASE
	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
Residential (R-1 and R-2)	$ 7,319,056	$ -	$ -	$ 67,896,045	$ -	$ -	$ -	$ 67,896,045	$ 31,431,039	$ 421,999,818	8.05%
Residential (R-3 and R-4)	$ 9,785,245	$ -	$ -	$ 8,675,717	$ -	$ -	$ -	$ 8,675,717	$ 3,494,763	$ 46,921,430	8.05%
EMA G1/T1 BOS	$ -	$ 27,699,313	$ 4,135,817	$ (2,117,700)	$ -	$ 27,699,313	$ 319,053	$ (1,798,646)	$ (2,441,156)	$ 31,802,109	-7.13%
EMA G2/T2 BOS	$ -	$ 224,547,957	$ 33,527,516	$ 7,411,363	$ -	$ 224,547,957	$ 2,586,445	$ 9,997,808	$ (10,014,573)	$ 257,807,783	-3.74%
EMA G3/SBG3/WR BOS	$ -	$ 69,807,182	$ 10,422,991	$ 10,365,266	$ -	$ 69,807,182	$ 804,071	$ 11,169,337	$ 4,223,945	$ 80,146,954	5.56%
EMA G0/G1/G6 CAM	$ 521,026	$ -	$ -	$ 398,981	$ -	$ -	$ -	$ 398,981	$ 633,105	$ 8,500,202	8.05%
EMA G2 CAM	$ 3,358,246	$ -	$ -	$ 340,205	$ -	$ -	$ -	$ 340,205	$ 1,014,971	$ 13,627,212	8.05%
EMA G3/SB1/SBG3 CAM	$ 5,876,855	$ -	$ -	$ 2,549,498	$ -	$ -	$ -	$ 2,549,498	$ 654,026	$ 8,781,090	8.05%
EMA G4 CAM	$ 66,151	$ -	$ -	$ 17,956	$ -	$ -	$ -	$ 17,956	$ 9,245	$ 124,125	8.05%
EMA G5 CAM	$ 134,669	$ -	$ -	$ (8,983)	$ -	$ -	$ -	$ (8,983)	$ 13,473	$ 180,891	8.05%
EMA G1/G7 COM	$ 8,322,276	$ -	$ -	$ 763,864	$ -	$ -	$ -	$ 763,864	$ 3,002,539	$ 40,312,734	8.05%
EMA G2 COM	$ 3,544,922	$ -	$ -	$ (902,315)	$ -	$ -	$ -	$ (902,315)	$ 832,704	$ 11,180,065	8.05%
EMA G3 COM	$ 3,574,564	$ -	$ -	$ (1,303,775)	$ -	$ -	$ -	$ (1,303,775)	$ 464,550	$ 6,237,147	8.05%
EMA G4 COM	$ 35,018	$ -	$ -	$ 5,283	$ -	$ -	$ -	$ 5,283	$ 6,009	$ 80,682	8.05%
EMA G5 COM	$ 129,336	$ -	$ -	$ 101,705	$ -	$ -	$ -	$ 101,705	$ 40,544	$ 544,357	8.05%
EMA G6 COM	$ 54,390	$ -	$ -	$ 12,015	$ -	$ -	$ -	$ 12,015	$ 5,748	$ 77,174	8.05%
WMA Optional Water Heating 23	$ 2,383	$ -	$ -	$ 814	$ -	$ -	$ -	$ 814	$ 724	$ 9,723	8.05%
WMA Optional Church 24	$ 84,161	$ -	$ -	$ 30,159	$ -	$ -	$ -	$ 30,159	$ 26,903	$ 361,200	8.05%
WMA G-0/T-0	$ -	$ 26,629,835	$ 3,976,132	$ 5,998,129	$ 3,709,568	$ -	$ -	$ 2,288,561	$ 1,978,065	$ 26,557,918	8.05%
WMA G-2/T-4	$ 1,444,871	$ -	$ -	$ 893,274	$ -	$ -	$ -	$ 893,274	$ 885,351	$ 11,886,907	8.05%
WMA T-2	$ 3,984,262	$ -	$ -	$ 1,644,495	$ -	$ -	$ -	$ 1,644,495	$ 1,141,803	$ 15,330,088	8.05%
WMA T-5	$ 1,969,260	$ -	$ -	$ 471,484	$ -	$ -	$ -	$ 471,484	$ 380,690	$ 5,111,230	8.05%
Street Lighting S-1/S-2 EMA	$ 1,289,368	$ -	$ -	$ 622,176	$ -	$ -	$ -	$ 622,176	$ 488,819	$ 6,562,992	8.05%
Street Lighting S-1/S-2 WMA	$ 566,396	$ -	$ -	$ 259,852	$ -	$ -	$ -	$ 259,852	$ 377,146	$ 5,063,643	8.05%
Total Company	$ 52,062,455	$ 348,684,287	$ 52,062,455	$ 104,125,509	$ 3,709,568	$ 322,054,452	$ 3,709,568	$ 104,125,509	$ 38,650,434	$ 999,207,475	4.02%

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

<u>Notes:</u>

(A) RR-DPU-50(e), Exhibit ES-RDP-2 (ALT1), Schedule RDP-2 (East), Page 4, Col. (a) and RR-DPU-50(e), Exhibit ES-RDP-2 (ALT1), Schedule RDP-2 (West), Page 4, Col. (a)

(B) sum of current revenue from RR-DPU-50(k) at Exhibit ES-RDP-8 (ALT1), Workpaper RDP-9 (East) and Exhibit ES-RDP-8 (ALT1), Workpaper RDP-9 (West) with modified calcuation for Basic Service revenue

(C) Change in revenue for reconciling rates

(D) RR-DPU-49(B), Page 2, Line 10 + RR-DPU-49(C), Page 2, Line 10 + RR-DPU-49(D), Page 2, Line 10 and RR-DPU-49(E), Page 2, Line 10

(E) For residential and SL: RR-DPU-49(J), Page 3-4, Line 10
For C&I: Col (D)/ (Col. (D) (Total) – (Col. (D) residential + Col. (D) SL)) x (Col. (D) (Total) – (Col. (E) residential + Col. (E) SL))

(F) For residential and SL: RR-DPU-49(J), Page 3-4, Line 14
For C&I: Col. (D)/ (Col. (D) (Total) – (Col. (D) residential + Col. (D) SL)) x RR-DPU-49(J), Page 3-4, Line 14 (Total) – (Col. (F) residential + Col. (F) SL)

(G) Col. (E) - Col. (A) - Col. (F) + Col. (C)

(H) 10% * Col. (B)

(I) If Col. (H) < Col. (G), then Col. (G) - Col. (H), otherwise zero

(J) If Col. (I) is greater than zero, then zero, otherwise Col. (E)

(K) If Col. (J) equals zero, then zero, otherwise (Col. (J)/Col. (J) (Total)) x (Col. (I) (Total))

(L) If Col. (I) equals zero, then Col. (G) + Col. (K), otherwise Col. (H)

(M) If ((Col. (L) - Col. (C))/Col. (A) is greater than the base rate cap increase, then (Col. (L) - Col. (C) - (Col. (A) x base rate cap increase)), otherwise zero

(N) If Col. (M) is greater than zero, then zero, otherwise Col. (J)

(O) Col. (M) (Total) x (Col. (N) / Col. N (Total))

(P) Col. (L) - Col. (M) + Col. (O)

(Q) If ((Col. (P) - Col. (C))/Col. (A) is greater than the base rate cap increase, then (Col. (P) - Col. (C) - (Col. (A) x base rate cap increase)), otherwise zero

(R) If Col. (Q) is greater than zero, then zero, otherwise Col. (N)

(S) Col. (Q) (Total) x (Col. (R) / Col. R (Total))

(T) Col. (P) - Col. (Q) + Col. (S)

(U) Col. (T) - Col. (C)

(V) Col. (A) + Col. (U)

(W) Col. (U) / Col. (A)

V. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That NSTAR Electric Company and Western Massachusetts Electric Company shall file all rates and charges required by NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05 (November 30, 2017) and shall design all rates in compliance with the directives set forth herein; and it is

FURTHER ORDERED: That the new rates shall apply to electricity consumed on or after February 1, 2018, but unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05 (November 30, 2017) and the directives set forth herein; and it is

FURTHER ORDERED: That NSTAR Electric Company and Western Massachusetts Electric Company shall comply with all other orders and directives contained in this Order.

By Order of the Department,

/s/

Angela M. O'Connor, Chairman

/s/

Robert E. Hayden, Commissioner

/s/

Cecile M. Fraser, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.