STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 19-057

IN THE MATTER OF: **PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY**

Distribution Service Rate Case

REDACTED

DIRECT TESTIMONY

OF

AGUSTIN J. ROS

December 20, 2019

TABLE OF CONTENTS

LIST OF ATTACHMENTS

I. INTRODUCTION

Q. Please state your name, address, employer, position, and professional qualifications.

A. My name is Agustin J. Ros, and I am a Principal at the Brattle Group. My expertise is in public utility economics including electricity cost of service and performance-based ratemaking, competition and market power analysis, demand studies and econometric modelling. I teach a class at the annual Edison Electric Institute ("EEI") Advanced Rate Course in Madison, Wisconsin, on embedded and marginal cost of service as well as efficient rate design principles and practices. I am an Adjunct Professor at the International Business School at Brandeis University where I teach a course on regulation and antitrust economics with a focus on public utilities. My research on public utility and competition issues has been published in *Public Utilities Fortnightly*, *The Electricity Journal*, *The Energy Journal, The Journal of Regulatory Economics*, *The Review of Industrial Organization*, *The Review of Network Economics*, T*elecommunications Policy* and *Info*. I have a B.A. in economics from Rutgers University and an M.S. and Ph.D. in economics from the University of Illinois at Champaign-Urbana. I attach my CV as an Attachment, AJR-1.

Q. Please describe the scope of your testimony.

A. The Staff of the New Hampshire Public Utilities Commission asked me to review and comment on the marginal cost of service ("MCOS") study that Eversource Utilities submitted in this proceeding. Eversource witness Amparo Nieto prepared the Eversource MCOS study ("the Eversource Study" or "the Study") and describes the methodology and approach in her direct testimony.

Q. Please describe your general approach to reviewing the Eversource Study.

A. I reviewed the general methodology and approach that the Study used with respect to the different components of the distribution marginal costs to determine whether the approach is generally consistent with underlying economic costing theory and practice.

I also reviewed and checked much of the underlying data analysis used in the Study. My review of the methodology and underlying data analysis led me to submit a number of data requests to answer doubts I had about particular issues and to clarify and explain why certain decisions were made.

Q. How is your testimony structured?

A. In Section II, I provide background on electricity marginal costs and lay out some general approaches and practices to estimate electricity marginal costs and to assess the Eversource Study. In Section III, I provide a detailed discussion of the main elements of the Eversource Study including the primary and local distribution systems and facilities, the customer costs, Operations and Maintenance ("O&M") and Costing Period for Time Differentiation. Lastly, in Section IV, I provide my analysis and observations on some of the key aspects of the study and provide recommendations and conclusions.

II. BACKGROUND ON ELECTRICITY MCOS STUDIES

Q. Please define marginal costs.

A. Marginal cost is the change in the total costs of providing a unit change in the output of a good or service. Marginal cost is a forward-looking concept, examining and estimating the economic resources that society will likely incur when producing an additional unit of a good or service. The marginal cost concept is different from the embedded cost concept, the main objectives of which are to assign and allocate the historically incurred costs of providing a good or service.

The precise definition of marginal costs involves estimating the present value of the cash flows caused by a permanent increase in production.[1] Specifically, marginal cost is the difference between two incremental system costs where incremental system cost

[1] *See* Ralph Turvey, "Marginal Cost," *The Economic Journal*, June 1969, for one of the earliest discussions on calculating marginal costs.

is the change in the cost of providing an increment of service and not just one additional unit. The first incremental system cost is the change in the present value of the flow of costs caused by a permanent increase in production. The second incremental system cost reflects the same increase in production deferred by one year. The difference in the two incremental cost flows is the first-year marginal cost. This calculation is known as the deferral approach to calculating first-year marginal costs.

Q. What are the different categories of marginal costs for electricity production?

A. Electric utility marginal costs consist of three main categories: marginal capacity costs—also referred to as marginal demand costs—marginal energy costs and marginal customer costs. Marginal capacity costs are the change in total electricity costs resulting from an increase in customers' peak-period (instantaneous) demands. In the production of electricity, there are marginal generation, transmission and distribution capacity costs. Marginal energy costs are the change in total electricity costs resulting from an increase in the demand for energy during a particular interval in time. Marginal energy costs consist of the fuel costs and the variable O&M expense required to produce the energy as well as the energy losses associated with increased usage—*i.e.*, transmitting electricity from the generation source to the load source necessarily entails energy losses that need to be made up through additional generation to meet demand. Marginal customer costs consist of the change in total electricity costs resulting from an increase in the number of customers.

Q. What are the relevant marginal costs for this proceeding?

A. Eversource is an electricity distribution provider. Electricity distribution gives rise to all three marginal costs concepts in theory—marginal capacity costs, marginal energy cost and marginal customer costs—although in practice, the two main categories in an electricity distribution MCOS study are marginal capacity costs and marginal customer costs. Marginal energy costs in an MCOS distribution study are accounted for in the loss factors. In the Eversource MCOS study, the two main categories of distribution marginal cost analysis are the marginal capacity costs and the marginal customer costs with loss factors to account for energy losses applied as a step within the MCOS study.

Q. What are marginal costs used for in the regulation of the electricity sector?

A. Marginal costs play an important role in the regulation of the electricity sector in that they can be used for pricing and rate design objectives such as establishing dynamic pricing and time of use/time of day rates and for setting appropriate price floors to customers for competitive and economic development purposes. Marginal costs are also used for internal resource planning, for company decision-making, and for wholesale transactions. Marginal costs can also be used, in part, for cost allocation purposes in a rate case proceeding.

Q. What are the different types of methodologies that exist for calculating marginal distribution costs?

A. There are two commonly used methodologies for calculating marginal distribution investment costs in theory. The first is the system planning approach and the second is the use of statistical/regression analysis ("regression analysis"). Since the Eversource Study uses the system planning approach, I describe that approach.

The system planning approach follows in the spirit of the marginal cost definition that I discussed previously. Under the system planning approach, electricity engineers and system planners determine the amount of distribution investment that is required in the short- to medium-term due to an increase in peak demand and the cost analyst uses this information to calculate marginal costs. Depending on the availability of the data, the cost analyst performs the analysis for different parts of the distribution system, such as the primary and secondary level. The result of this analysis is a marginal investment per unit of demand, such as per MW or per kW. The cost analyst then annualizes the investment using an economic carrying charge and accounts for additional shared investments and expenses such as general plant, materials and services and administrative and general services. Finally, the cost analyst estimates marginal O&M expenses associated with the marginal investment and includes them in the MCOS calculation.

Q. How are marginal distribution O&M costs typically calculated in a marginal cost of service study?

A. A standard approach is to calculate O&M costs on a per-unit of output basis—*i.e.*, calculate average per-unit O&M expenses—and to utilize that statistic as the value for marginal O&M costs.[2] Specifically, the standard approach begins with historical data on O&M costs for the different investment categories and converts those expenses into an inflation-adjusted series, similar to the conversion that the cost analyst makes for calculating marginal distribution investment. The next step is to convert the O&M expenses to a per-unit level of peak demand—for plant-related O&M expenses—or a per-unit level of customer demand—for customer-related O&M expenses—and examine some basic statistics of that data series. The resultant statistics from the data series—*i.e.*, the mean value for the series or the mean value for more recent years or the use of a simple linear extrapolation—provides the O&M expenses that are added to the annualized marginal investments discussed above.

III. EVERSOURCE MCOS STUDY

Q. Please provide a high-level summary of the methodology of Eversource's MCOS study.

A. The Eversource Study adopts a system planning approach to calculate the marginal distribution investment costs. The Study divides the Eversource system into five different cost centers: Bulk Station, Non-Bulk Station, Trunk-Line, Local Distribution Facilities, and Customer. The Bulk Station, Non-Bulk Station, and Trunk-Line cost centers all relate to primary distribution. For each cost center, the Eversource Study develops an estimate of the budgeted investment and then unitizes that cost on a capacity (per kW) or per customer basis. The unitized costs are then multiplied by a Real Economic Carry Charge ("RECC") and "loaders" including O&M. These cost

[2] *See* National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, ("*NARUC Manual*") Chapter 10, p. 131 for a discussion on calculating marginal O&M expenses for transmission capacity costs, an approach that is applicable to O&M expenses for distribution capacity costs.

centers and the unitization approach are summarized in Figure 1. I describe the calculation details for each of these cost centers in the following sections.

Figure 1: Eversource MCOS Cost Centers and Unitized Cost Approaches

Category	Description	Unitized Cost Approach
Primary Distribution – Bulk Station	Converts load from transmission system (115 kV) to 34.5 kV or 12 kV.	$/kW incremental capacity
Primary Distribution – Non-Bulk Station	Converts load from bulk station of 12 kV or 4 kV.	$/kW incremental capacity
Primary Distribution – Trunk-Line	Connects bulk and non-bulk substations to local primary taps.	$/kW incremental capacity
Local Distribution Facilities	Primary taps, line transformers, and secondary lines.	$/kW design demand
Customer	Meter costs, customer service drop costs, and customer accounts and customer expenses.	$/customer

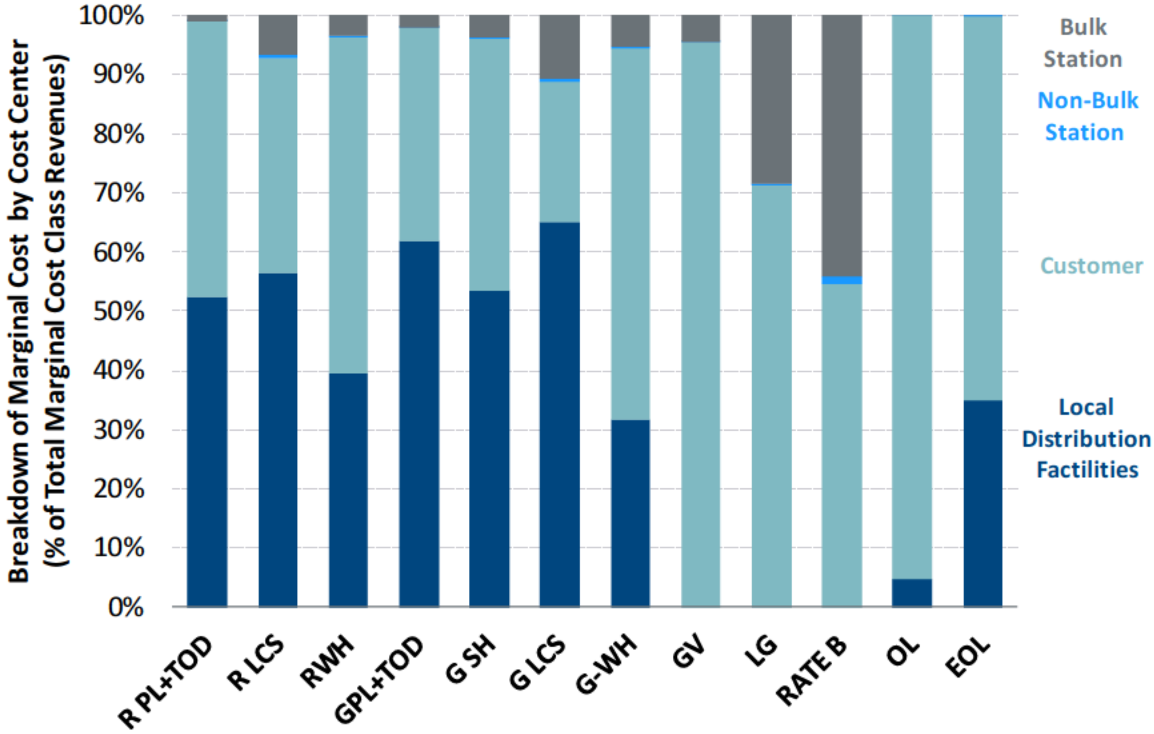
Source: Nieto Direct; pp. 10-12; Bates 001737-39.

Q. Do each of the cost centers contribute equally to the MCOS by rate class?

A. No. For some classes, the largest components are the Local Distribution Facilities and Customer costs, while for others the Bulk Station and Customer costs have the largest impact, as shown in Figure 2. Although the Bulk Station costs are a large component for a few rate classes, these are relatively small rate classes and overall the total contribution of the Bulk and Non-Bulk Stations in the MCOS is small. Because Eversource did not identify any investments over the 5-year period, the marginal cost for the Trunk-Line cost center is zero.

Redacted

Figure 2: Breakdown of Marginal Cost by Cost Center and Rate Class



Source: Brattle calculation based on AJR Attachment-2 (Data Response Staff 14-002 Attachment).

A. Primary Distribution System

Q. Please explain how the Eversource Study developed the unitized cost for the Bulk Station cost center.

A. The Study uses "project expectations" as per Eversource's 5-year capital plan. From the 5-year capital plan, the Eversource Study included stations expected to be over 75% of current rating due to load growth based on a 90/10 forecast.[3] The 90/10 forecast indicates that load is expected to exceed the forecast with less than 10% probability. The Eversource Study identifies **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** investments that meet the criteria of loading over 75% of nameplate capacity by 2024.[4]

---

3 I understand that based upon the Staff testimony of Kurt Demmer, the Staff is addressing the appropriateness of the 75% loading criteria.

4 Confidential Attachment AJR-3 (Confidential OCA 2-51 Attachment E).

Redacted

Q. Does the Eversource Study include all projects identified with anticipated usage exceeding the 75% usage threshold for peak demand?

A. No. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Figure 3: Eversource Bulk Station Overload
[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Sources and Notes:
[2] – [5]: Confidential Attachment AJR-3 (Confidential OCA 2-51 Attachment E).
[6] = 75% × [5].
[7] = [4] / [5].
[8] = [4] − [6].

Q. For the projects included, does the Study use the cost described in the capital budget for each substation?

Redacted

A. No. The costs used by the Study differ from those in the capital budget for two reported reasons. First, for all projects, the total project costs included in the Study are lower than those included in the capital budget, which is consistent with the concept that the MCOS-related costs are a subset of the total project costs. Specifically, the Study excludes investment costs that are related to substation reconfiguration or retirement of obsolete equipment.[5] This is a generally accepted practice and consistent with the purpose of a marginal cost study. Second, the Eversource Study relies on estimates of transformer replacement costs rather than budgeted project costs.[6]

While the total costs used within the Study are consistent with the capital budget, the timing of the expenditures is not consistent for four stations. For these four stations (Station 4, Station 6, Station 9, and Station 14), the Study includes *annual* expenditures that exceed the capital budget *for that year*. As one example, the capital budget indicates that expenditures on the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Station 9) are not anticipated to begin until 2021.[7] However, the annual expenditures used in the Eversource Study begin one year earlier in 2020.[8] Individual years where the annual expenditures included in the Study exceed the capital budget for that year are shown in red in Figure 4.

[5] Nieto Attachment MCOSS-1, Marginal Cost of Distribution Service Study and Implications for Rate Design; p. 8; Bates 001769.

[6] Attachment AJR-4 (Data Response Staff 14-041).

[7] Confidential Attachment AJR-5 (Confidential OCA 6-105 Attachment D).

[8] Confidential Attachment AJR-6 (Confidential OCA 2-51 Attachment A).

Redacted

Figure 4: Comparison of MCOSS Bulk Station Project Spending with Eversource Five-Year Budget

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Source: Confidential Attachment AJR-5 (Confidential OCA 6-105 Attachment D) and Confidential Attachment AJR-6 (Confidential OCA 2-51 Attachment A).

Q. Can the mismatch in timing of expenditures between the annual expenditures in the capital budget affect the Study's results?

A. The timing of expenditures can influence the results in at least two different ways. First, the Study is in constant 2019 dollars, not nominal, meaning the costs are adjusted to account for inflation.[9] A dollar invested in 2019 does not have the same value as a dollar invested in 2020 due to inflation. For example, if inflation was 2%, $1 dollar in 2020 would be worth $0.98 in 2019 constant dollars. Thus, the timing of investments has an impact on investments used in the Study.[10]

[9] Attachment AJR-7 (Data Response Staff 14-040).

[10] Witness Nieto's testimony does not explain why the $2.5 million cost per transformer at the bulk station is unaffected by inflationary adjustments to calculate constant 2019 dollars.

Second, the timing of expenditures affects the present value of expenditures due to the time value of money, commonly expressed, as "I'd rather have a dollar today than tomorrow." The present value calculation uses a discount rate that represents the time value of money, which is often reflected in the utility's weighted average cost of capital. The Eversource Study's approach does not discount the project costs to determine a present value of costs, which would be influenced by the timing of the expenditures.[11] In Section IV, I discuss the implications of these two points for the Study.

Q. Turning to the capacity portion of the Bulk Station MCOS calculation, how did the Study determine the capacity to be used for each project?

A. The Study calculated the total incremental capacity, meaning the total capacity added to the bulk station adjusted by the 75% usage target.[12] For example, if an investment added 10 MW of capacity, the total incremental capacity would be 7.5 MW.

Q. With the project investment cost and project capacity, how did the Eversource Study calculate the unitized cost?

A. To calculate the unitized marginal cost, the Study divided the total project investment costs by the incremental capacity of all projects. Collectively, the projects have a capital expenditure of $27.5M in 2019 inflation-adjusted dollars and an incremental capacity of 151 MW, which results in a unitized cost of $182.51 per kW. Figure 5 below shows unitized marginal costs for the bulk station category, both on a total basis (i.e., including all investments), following the discussion above, and on a project-by-project basis (i.e., project capacity divided by project capital expenditure).

To establish the system-wide unitized cost, the Study then applies two weighting factors, the share of retail peak load served by the expanded stations over 2020-2024

[11] This is evidenced by the labeling of costs within the Eversource Study model, the calculation of the marginal costs (as demonstrated subsequently in Figure 5), and Witness Nieto's response in Attachment AJR-7 (Data Response Staff 14-40).

[12] Nieto Attachment MCOSS-1; p. 8; Bates 001769.

Redacted

and the share of total retail distribution load fed from bulk stations, to yield the system-wide Bulk Station marginal cost of $36.33 per kW.[13] This means that the bulk stations that require capital expenditures over the next five years represent approximately 20% of retail load.

Figure 5: Bulk Station Unitized Cost Calculation
[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Sources and Notes:

[2] - [3]: Confidential Attachment AJR-6 (Confidential OCA 2-51 Attachment A).

[4] = 75% × ([3] – [2]). Total incremental capacity may not equal the sum of station incremental capacity due to rounding.

[5]: Confidential Attachment AJR-6 (Confidential OCA 2-51 Attachment A). Costs are in 2019 dollars.

[6] = [5] / [4]. May not result in what is exactly shown in the column due to rounding.

[7] = [6] × 20.26% × 98.25%. 20.26% is the share of retail load served by the expanded stations over 2020-2024, and 98.25% is the share of total retail distribution load fed from bulk stations

Q. Did the calculation of the Non-Bulk Station unitized cost follow the same approach as the bulk unitized cost?

A. For the most part, yes. Unlike the bulk projects, the investments included in the Non-Bulk Station calculation were not determined based on forecasted loadings. Instead, the Company estimated that three non-bulk capacity station expansions would be

[13] Nieto Attachment MCOSS-1; pp. 9 and 21; Bates 001770 and 001782.

needed between 2022 and 2024.[14] In lieu of specific project data, the Eversource Study assumed (with consultation with the Company) that the projects would include installation of three 12.5 MVA transformers to replace three existing transformers.[15] The Study reported that the costs used for each project were the "typical costs" of installing a 12.5 MVA substation transformer.[16] The capacity for the substation expansions were based on the incremental capacity provided by the 12.5 MVA transformers, as shown in Figure 6. The incremental capacity is not adjusted by the 75% factor used for the bulk stations as the Company bases replacement on the transformers long-term rating.[17] The total cost divided by total incremental capacity results in a Non-Bulk Station unitized value of $250.60 per kW.

To establish the system-wide unitized cost, the Study again applies two weighting factors, the share of retail peak load served by the expanded stations over 2020-2024 and the share of total retail distribution load fed from non-bulk stations, to yield the system-wide Non-Bulk Station marginal cost of $2.41 per kW.[18]

[14] Attachment AJR-8 (Data Response Staff 14-007).

[15] Specifically, Witness Nieto assumed that the transformers would replace two 5.25 MVA transformers and one 6.25 MVA transformer. Attachment AJR-8 (Data Response Staff 14-007).

[16] Confidential Attachment AJR-9 (Confidential Data Response Staff 14-043).

[17] Nieto Attachment MCOSS-1; p. 9; Bates 001770.

[18] Nieto Attachment MCOSS-1; pp. 9 and 21; Bates 001770 and 001782.

Redacted

Figure 6: Non-Bulk Station Unitized Cost Calculation

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Sources and Notes:

[2] - [3]: Attachment AJR-8 (Data Response Staff 14-007).

[4] = [3] – [2].

[5]: Nieto Attachment MCOSS-1, Table A.2.2, Bates 001788. Costs reflect the typical costs of installing a 12.50 MVA transformer, and are in 2019 dollars. The MCOSS model provides the total cost of all three upgrades, and each project is assumed to cost the same amount.

[6] = [5] / [4]. MVA is assumed to be equivalent to MW. See Attachment AJR-10 (Data Response Staff 14-042), which discusses the conversion from MW to MVA for bulk station project incremental capacity.

[7] = [6] × 5.51% × 17.46%. 5.51% is the share of retail load served by the expanded stations over 2020-2024, and 17.46% is the share of total retail distribution load fed from non-bulk stations.

B. Local Distribution Facilities

Q. Is the Eversource Study's approach to the Local Distribution Facilities marginal cost similar to that for the primary cost centers?

A. No, the approach varies in two key ways. First, the Local Distribution Facilities calculation is based on design standards for customer types, which specifies the maximum load that the customer is expected to impose on the system.[19] This means that the calculation is based on the cost associated with a customer's maximum design load rather than the customer's actual peak demand on the system. Thus, the approach adopted by the Study implies that the costs may not be avoided or reduced based on

[19] Nieto Direct; p. 16, lines 14-17; Bates 001743.

usage.[20] The Study refers to this approach as the "rental value" of the average customer in the class.[21] Second, the Local Distribution Facilities calculation is based on a historical sample of connection jobs rather than a going-forward anticipated cost.

Q. Please describe the data used by the Eversource Study to calculate unitized cost for Local Distribution Facilities.

A. The Study uses a combination of a sample of historical estimates for customer connection jobs to develop the costs and the design standards for capacity, as shown in Figure 7. The Study used historical estimates of costs rather than actual costs on the justification that up-front payment by the customer is based on the estimated cost of the job rather than ultimate cost of completing the job.[22]

Figure 7: Local Distribution Facilities Work Order Summary

Construction Type	Transformer	Number of Work Orders	Average Net Facilities Cost after CIAC (2019 $)	Average Net Facilities Cost per kVA (2019 $/kVA)
Single Phase Underground	Y	384	$5,715	$127
	N	273	$2,122	n/a
Single Phase Overhead	Y	142	$3,311	$116
	N	91	$2,587	n/a
Three Phase Underground	Y	63	$7,318	$141
	N	126	$371	n/a
Three Phase Overhead	Y	22	$10,408	$221
	N	29	$488	n/a

Source: Calculation Based on Attachment AJR-12 (OCA 7-14 Attachment, Replacement OCA 2-51 Attachment G) and Attachment AJR-13 (OCA 2-51 Attachment H). Costs are based on estimated rather than actual costs.

Q. How did the Study calculate the unitized cost from this sample?

[20] Witness Nieto states this explicitly in her testimony: "The design demand that the Company considers when installing a transformer and local lines is the maximum load that the customers connected to those facilities are expected to impose on the local distribution system. This is distinctly different from the coincident peak demands that are considered when designing plant at the upstream voltage levels." Nieto Direct; p. 16, lines 14-18; Bates 01743.

[21] Nieto Direct; p. 16, lines 19-20; Bates 01743.

[22] Attachment AJR-11 (Data Response Staff 14-036).

A. The Eversource Study followed a five-step approach to calculate a unitized cost, the results of which are summarized in Figure 8:

1. Filters the sample of jobs to include only those with a transformer cost;
2. For each remaining job, subtract contributions in aid of construction (i.e., customer contributions that reduce the utility's cost);
3. For each remaining job, divide the net cost by the transformer capacity;
4. Separate jobs into four categories based on the number of phases (single phase and three phase) and infrastructure type (overhead or underground), and calculate the average $/kW costs for each of the four job types; and
5. Calculate weighted averages of single phase and three phase jobs based on the relative shares of overhead and underground projects.

Figure 8: Unitized Local Distribution Facilities Cost per kVA

Single Phase		
Underground		
Average Net Facilities Cost per kVA	[A]	$127
Average Share	[B]	21%
Overhead		
Average Net Facilities Cost per kVA	[C]	$116
Average Share	[D]	79%
Single Phase Weighted Average Net Cost per kVA	***[E]***	***$118***
Three Phase		
Underground		
Average Net Facilities Cost per kVA	[F]	$141
Average Share	[G]	39%
Overhead		
Average Net Facilities Cost per kVA	[H]	$221
Average Share	[I]	61%
Three Phase Phase Weighted Average Net Cost per kVA	***[J]***	***$190***

Sources and Notes:

[A] - [D]: Attachment AJR-12 (OCA 7-14 Attachment, Replacement OCA 2-51 Attachment G). All costs are in 2019 dollars.

[E] = [A] × [B] + [C] × [D].

[F] - [H]: Attachment AJR-13 (OCA 2-51 Attachment H). All costs are in 2019 dollars.

[J] = [F] × [G] + [H] × [I].

C. Marginal Customer Costs

Q. What costs does the Eversource Study include in the cost center for Customer costs?

Redacted

A. The Study includes three different types of costs: meter costs, customer service drops, and customer account/customer expenses (i.e., costs associated with adding and maintaining a new customer account). The approach to quantifying the costs for the marginal customer differ between the cost centers. For metering, the Eversource Study relies on the “current installed cost” of typical meters by class, presumably from the Company.[23] Presumably, this is equivalent to the cost of a new meter going forward; however, the Study does not explicitly define the meter costs in this way.

The Eversource Study’s approach to creating a unitized per customer cost for service drops mirrors that used for the Local Distribution Facilities. The Eversource Study calculates the annual average customer service drop net cost (total cost minus customer contribution) for underground and overhead projects.[24] These average costs are weighted by shares of overhead and underground projects. This process is illustrated in Figure 9 for the R-P&L class.

Figure 9: Example of Service Drop Cost for R-P&L

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Sources and Notes:

[A] - [D]: Confidential Attachment AJR-6 (Confidential OCA 2-51 Attachment A).

[E] = [A] × [C] + [B] × [D].

[23] Nieto Attachment MCOSS-1; p. 14; Bates 001775.

[24] The overhead and underground per customer after CIAC Service Drop Investment are hardcoded in the model (rows [A] and [B] in Figure 9), so it’s unclear exactly how these values are calculated.

Finally, for customer accounts/customer expenses, the Eversource Study relies on 2016-2018 FERC Form 1 cost data and 2018 customer counts. To calculate marginal customer account-related expenses, the Eversource Study includes accounts: 901 (Supervision), 902 (Meter Reading Expenses), 903 (Customer Records and Collection Expenses), and 904 (Uncollectible Accounts), 905 (Misc. Customer Accounts Expenses). To allocate the FERC Form 1 costs to rate classes, the Eversource Study uses a mix of historical data and other approaches.[25] Of these accounts, the majority of costs arise from accounts 903 (67% of total) and 904 (24% of total). Similarly, for customer service and informational expenses, the Eversource Study relies on 2014-2018 FERC Form 1 cost data and 2018 customer counts. The marginal customer service expenses include accounts: 907 (Supervision), 908 (Customer Assistance), 909 (Information & Instructional), and 910 (Misc. Customer Service & Info). Of the accounts, only 908 and 910 are non-zero, with account 908 making up nearly 100% of total costs.[26]

In general, the Eversource Study builds up costs based on these accounts in the 2017 FERC data and then interpolates to produce an average value across 2014-2018. The interpolation calculates a per residential meter cost in the years 2014 and 2018 and then uses weightings to calculate rate specific costs. Rather than recreate analyses for 2014-2016 and 2018, the Study calculates an "equivalent" number of residential meters, called the "weighted number of customers," for each rate class in 2017 based on the 2017 costs.[27] The Study then calculates the ratio between the annual number of accounts and the sum of the "meter weighted" accounts. To calculate the per customer costs in 2014-2016 and 2018, the Study divides the total customer account expenses by the number of accounts, adjusted by the meter weighting. Because the accounts were

[25] Accounts 902 and 904 are allocated based on Company provided data. Account 903 has an unexplained hard-coded allocation. Account 905 is allocated evenly on a per customer basis. Account 901 is allocated proportionally based on the class-total share of costs in accounts 902-905.

[26] Account 908 is only allocated to Rate B classes based on class customer count. Account 910 is allocated evenly on a per customer basis.

[27] For example, if the cost per residential customer was equal to $10 per customer and the cost per general service customer was equal to $5 per customer, then two general service customers would be equivalent to one residential customer ($10 divided by $5).

normalized to reflect an equivalent cost, this division results in the cost per residential accounts (assuming that the 2017 ratios of costs between the customer classes remains constant.)

D. Operations and Maintenance Costs

Q. How were the O&M costs calculated within the Study?

A. The O&M costs were calculated using average 2014-2018 historical FERC Form 1 data.[28] For the cost center specific FERC Form 1 accounts, relevant O&M expenses were summed and then increased to reflect a share of O&M overhead amounts. These O&M costs were then normalized per customer or kilowatt, inflated to constant dollars, and averaged over the years of historical data. While this general approach was used across cost centers, specific calculation details varied cost center to cost center. For example, to calculate the O&M of Local Distribution Facilities, the Study first sums relevant overhead and underground line maintenance accounts and then increases those amounts based on a pro rata share of O&M overhead accounts. The share of these O&M accounts was then multiplied by the percentage of primary and secondary lines (relative to all circuit line miles) to assign the Local Distribution Facilities cost center a pro rata share of the total relevant expenses.

The use of FERC Form 1 data for calculating marginal O&M expenses is a standard and well-accepted approach in MCOS studies.

E. Development of Costing Periods for Time Differentiation

Q. How does time differentiation of rates tie into marginal costs?

A. The costs of expanding the system can be allocated to certain time periods which are driving the need for investment. Investment needs in the primary distribution system are typically driven by peak demands (either local system, or system-wide). Identifying

[28] The O&M for stations, local distribution facilities, meters, and overhead include 13 FERC Form 1 accounts: 580, 582, 583, 584, 588, 590, 591, 592, 593, 594, 595, 597, and 598.

the time periods during which peaks occur allows costs to be allocated to these time periods, which can be used to develop time of use or other rate structures.

To estimate the periods when peak would occur, the Study developed a "probability of peak calculation." The probability of peak approach adopted by the Study essentially groups similar hours and considers the statistical likelihood that each group of hours will produce the peak load. More specifically, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

IV. ANALYSIS

Q. Based on your review of the Eversource Study's analysis, do you have comments on any of the methodological approaches adopted?

A. Yes. I comment on two issues. The first has to do with the calculation of the Bulk and Non-Bulk Station marginal investment costs, while the second involves the calculation of the periods for time differentiation of the primary distribution system costs.

Q. What are your comments on the calculation of the Bulk and Non-Bulk Station marginal investment costs?

29 [redacted]

A. The Eversource Study calculates the marginal investment costs of Bulk and Non-Bulk Stations by taking the sum of the expected growth-related investment (in constant 2019 dollars) over the next 5 years and dividing it by the incremental capacity from these investments. By calculating a straight sum of the investment costs for Bulk and Non-Bulk Stations, regardless of the year of implementation, expenditures further out in the future (say 2024) are weighted the same (in constant 2019 dollars) as expenditures in 2019. This approach is sometimes referred to as the Total Investment Method ("TIM") an approach with early support in the costing literature and that has been used in the past by Commissions.[30]

An alternative approach would take into account the time value of money and place less weight on investments later in the period compared to 2019. The Discounted Total Investment Method ("DTIM") is one alternative approach recognized in the literature and used in practice as well.[31] The DTIM takes into account the *timing* of investments over the planning horizon and by doing so places more weight in a marginal cost study on those investments that are expected earlier in the period. The DTIM properly discounts both the investments *and* the incremental capacity.[32]

Q. What reasons did Eversource give for not discounting the Bulk and Non-Bulk Station investments?

A. Eversource answered the following when asked why it did not discount investments:

> *The marginal cost that the study aims to estimate is the incremental or decremental cost associated with change in a unit of demand across the entire five-year period. The study does not presume the year the particular load change will take place. Thus, it does not seek to estimate the*

[30] See NARUC Manual, pp. 129-130, for a discussion on transmission marginal investment that applies a similar methodology as the Eversource Study. See also California Public Utilities Commission D.92-12-058 for a description of TIM for application in marginal gas transmission costs for revenue allocation.

[31] This approach is also described in California Public Utilities Commission D.92-12-058.

[32] The discounting of incremental capacity is justified by the very nature of capital—*i.e.*, the fact that the productive capacity of resources (*e.g.*, labor) embedded in capital is stored for use over the life of the equipment and is not expended concurrently with the provision of output. Mathematically, discounting the investments *and* the incremental capacity is required to prevent the marginal unit investment to tend to zero as the planning horizon increases.

incremental (or avoided) cost that the Company would experience if the load growth (or load reduction) took place in year 1 (2020) vs. year 2 (2021), etc. The MCOS study is designed to inform the ongoing marginal cost impact through distribution rates, which will be fixed for the foreseeable three or four years as opposed to being updated on an annual basis. In addition, in practice, the timing for a particular planned substations investment may shift by one year or more for reasons unrelated to station load, such as changes in the pace of available funds, or other reasons. In short, adopting a discounted cost approach would not add accuracy to the marginal cost calculation due to the purpose of the MCOS study coupled with the inherent uncertainty in the precise timing of the distribution investment project over the five-year period.[33]

Thus, there appear to be two main reasons for not discounting: (1) the uncertainty in timing of investment expenditures renders greater accuracy moot, and (2) because the marginal costs are used to inform rates over a 3-4 year period, the marginal costs should reflect a single marginal cost for the period.

Q. Do you agree with these two premises?

A. Neither are persuasive. Regarding the first, while I recognize the uncertainty in the precise timing for distribution investments, I do not agree that this uncertainty negates the value of using the best information available, *i.e.*, the Company's estimates of when expenditures would be made. As I understand it, the best information available depicts investments for the Bulk and Non-Bulk Stations occurring in different years during the period and it is proper and appropriate to use that information in the MCOS Study. Using the Company's estimates of expenditures would also negate the need to assume that all investments should financially be treated as occurring in year one (2019) versus any other year in the time horizon.

Regarding the second, I do not find the argument convincing. I do not see how the issue of distribution rates being either fixed over three or four years or being updated on an annual basis has a bearing as to whether to discount the investments in an MCOS Study—in other words whether to use the TIM or DTIM. When multiplied by the real economic carrying charge (RECC), both methodologies provide first year marginal

[33] Attachment AJR-7 (Data Response Staff 14-040).

annual costs that change each year based upon underlying inflation and technological assumptions embedded in the RECC. The issue of how these first year costs will be used in rate setting is separate from the issue of which methodology, TIM or DTIM, is more or less sound.

Q. Did you apply the DTIM methodology for the primary distribution system and compare that to the Eversource methodology?

A. Yes, the table below provides an estimate based, on high-level assumptions that would need to be refined, of the impact on the Study's results when the Bulk and Non-Bulk Station investments and incremental capacity are discounted. For the Bulk Station calculation, I used the investment profile in the budget and for the Non-Bulk Station calculation, I assumed that investments occurred during 2021-2024 and incremental capacity coming on line in 2022, 2023, and 2024. Discounting investment and incremental capacity under these assumptions—*i.e.*, implementing the DTIM approach—in this particular case slightly increases marginal costs of the Bulk Station investments on a $/kW-year compared to not discounting and using the TIM. For the Non-Bulk Station, there is practically no difference in the results.

Figure 10: Impact of Discounting Bulk and Non-bulk Station Investments

	Annualized System-Wide MC ($/kW-yr)	
Methodology	Bulk Station	Non-Bulk Station
DTIM Approach *Using Discounted Project Costs and Capacity*	$5.09	$0.30
TIM Approach *Using Total Project Costs and Capacity*	$4.94	$0.30

Sources and Notes:

Annualized marginal costs from the TIM Approach are from Nieto Attachment MCOSS-1; p. 21; Bates 001782.

Annualized marginal costs from the DTIM Approach are calculated by discounting project costs and incremental capacity using a 7.62% WACC from Quinlan Direct; p. 28, lines 6-8; Bates 000046.

Q. What is your recommendation on this point?

A. Although in this particular case the impact on the study will be relatively minor because the Bulk Station MCOS are small overall compared to total MCOS results, I recommend that the Study adopt the DTIM approach for calculating marginal capacity costs for the Bulk Stations using the investment profile in the budget. In general, I recommend future MCOS studies incorporate the DTIM approach as much as possible given the availability of company information and data constraints.

Q. Do you have comments on the time differentiation part of the Eversource Study that is utilized in rate design?

A. The approach taken by the Eversource Study to determine costing periods is sophisticated and complex. Complexity certainly has a place where necessary, but I believe it is appropriate to compare the Study's time differentiation results to results from a more straightforward and more parsimonious methodology, of which there are alternatives. As an example, a straightforward approach is to analyze and identify historical load data that falls within 1%, 5%, or 10% of peak load and to examine where those hour fall within a proposed rate design option. This approach is an example of a deterministic method for time differentiation and is a generally accepted practice in a marginal cost study.[34]

Q. Did you replicate the time differentiation analysis using a deterministic approach that considers the number of hours that fall within a pre-defined percentage of peak load?

A. Yes, and the results show that the months of June and September are important months as well, not just July and August.

Q. Please explain your analysis.

A. For each year, I calculated the number of hours that fall within 1%, 5% and 10% of that year's peak hour—these are "critical hours" and the number of critical hours increase as the threshold percentages increase, *i.e.*, going from 1% to 10%. I then matched the

[34] See Confidential Attachment AJR-15 (Confidential Data Response Staff 14-038)

critical hours to the different hour categories in Option A and Option B of the Study. For example, there are three hour categories in Option A: the first hour category is July and August Peak Hours, the second hour category is July and August Non-Peak Hours and the third category is "all other hours." By matching the critical hours to the different hour categories in Option A and Option B, I was able to calculate the percent of the critical hours that were contained in the different hour categories in Option A and Option B.

Figure 11 below presents my results. Taking the 1% critical peak hours, under the current TOU period, 100% of those critical hours fell within the year round peak period and 0% fell outside the year round peak period. The Eversource Study concurs as it found only a 1% probability of distribution peak occurring outside the year round peak period. Thus, my analysis and the Eversource analysis match fairly well for the current TOU periods.

With respect to Option A, however, my analysis found that 79% of the critical hours using the 1% critical hours fell within the July and August Peak hours defined in Option A, 0% fell within the July and August Off Peak hours, and 21% fell during the "all other hours." By contrast, the Eversource Study found only a 3% probability of distribution peak occurring during those "all other hours." When I increased the number of critical peak hours—using the 5% and 10% threshold—I obtained similar results; that is, I found a significant percentage of the "all other hours" containing those critical hours.

Figure 11: Comparison of Distribution Substation Peak Probability Under Different TOU Period Definitions

		Alternate Methodology		
Option and Period	Eversource Study Methodology	1% Threshold	5% Threshold	10% Threshold
Current TOU Period				
Year-Round Peak	99%	100%	100%	99%
Year-Round Off Peak	1%	0%	0%	1%
Option A				
Summer (Jul & Aug) Peak	92%	79%	81%	73%
Summer (Jul & Aug) Off Peak	5%	0%	0%	8%
All Other Hours	3%	21%	19%	19%
Option B				
Summer (Jun-Sep) Peak	94%	100%	99%	90%
Summer (Jun-Sep) Off Peak	6%	0%	1%	10%
All Other Hours	0%	0%	0%	1%

Sources and Notes: The Current TOU Period defines Peak hours as 7am to 8pm on non-holiday weekdays, while Options A and B define Peak hours as 11am to 7pm on non-holiday weekdays. Option A defines Summer as July and August, while Option B defines Summer as June-September. Option and Period definitions are from Nieto Attachment MCOSS-1; pp. 10-11; Bates 001771-72.

Probability of peak under the Eversource Study Methodology are from Nieto Attachment MCOSS-1; pp. 29-30; Bates 001790-91. The Eversource methodology calculates the probability of distribution peak occurring within the hours in the rate design category. The alternative methodology calculates the percentage of hours in the rate design category (i.e., Summer Peak, Summer Off Peak and All Other Hours) that are within 1%, 5% and 10% of peak load.

What seems to be driving the difference between my analysis and the Eversource Study is the months of June and September. Option B of the Eversource Study defines the summer months as June-September. The Eversource Study shows a 0% probability of distribution peak occurring during the "all other hours" of Option B. My analysis is in agreement in that it shows that using the 1% and 5% critical peak hours, none of those hours are in the "all other hours". When I increase the number of critical peak hours using the 10% threshold, I find that 1% are in the "all other hours," still a very small amount.

The overall conclusion from my analysis is that hours in June and September are important hours of the year as well for purposes of time differentiation. Therefore, it is appropriate to consider the months of June and September in the definition of the

Summer Months for time differentiation purposes, and by implication, for rate design analysis and associated tradeoffs.

Q. Does this conclude your testimony?

A. Yes.