

**THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION**

**PREPARED JOINT TESTIMONY OF ERICA L. MENARD AND JAMES E.
MATHEWS**

TRANSMISSION COST ADJUSTMENT MECHANISM (TCAM)

Docket No. DE 21-109

1 **Q. Please state your names, business addresses and your present positions.**

2 A. My name is Erica L. Menard. My business address is 780 North Commercial
3 Street, Manchester, NH. I am employed by Eversource Energy Service Company
4 as the Manager of New Hampshire Revenue Requirements and in that position, I
5 provide service to Public Service Company of New Hampshire d/b/a Eversource
6 Energy (“Eversource” or the “Company”).

7 My name is James E. Mathews. My business address is 107 Selden Street, Berlin,
8 CT. I am employed by Eversource Energy Service Company as the Manager of
9 Rates and Revenue Requirements, Transmission and in that position, I provide
10 service to the Eversource Energy affiliated companies in Connecticut,
11 Massachusetts and New Hampshire, including the Company.

12 **Q. Have you previously testified before the Commission?**

13 A. Ms. Menard: Yes, I have.

14 A. Mr. Mathews: Yes, I have.

1 **Q. What are your current responsibilities?**

2 A. Ms. Menard: I am currently responsible for the coordination and implementation
3 of revenue requirements calculations for Eversource, as well as the filings
4 associated with Eversource’s Energy Service (“ES”) rate, Stranded Cost Recovery
5 Charge (“SCRC”), Transmission Cost Adjustment Mechanism (“TCAM”),
6 Regulatory Reconciliation Adjustment mechanism (“RRA”), and Distribution
7 Rates.

8 Mr. Mathews: I am currently responsible for coordination and implementation of
9 transmission rate and revenue requirement calculations for Eversource. I also have
10 responsibility related to transmission rate filings before Eversource’s affiliated
11 companies’ three state utility commissions, as well as the Federal Energy
12 Regulatory Commission (“FERC”).

13 **Q. What is the purpose of your joint testimony?**

14 A. Ms. Menard: My testimony supports Eversource’s TCAM filing for rates
15 effective August 1, 2021. The testimony and supporting attachments present the
16 reconciliation through May 2021 for transmission costs as well as the proposed
17 TCAM rate for the forecast period to be effective August 1, 2021.

18 Mr. Mathews: My testimony is to support and describe the year-to-year change in
19 LNS and RNS rates.

1 **Q. What is Eversource requesting in this filing?**

2 A. Eversource is requesting approval of a forecasted average retail transmission rate
3 to be effective August 1, 2021, for a twelve-month billing period. In addition,
4 approval of the over- or under-recoveries resulting from the reconciliation of actual
5 transmission costs and revenues as compared to forecasted transmission costs and
6 revenues used in the previous rate filing is being requested. These requests are in
7 accordance with the Commission’s approval of the settlement in Docket No. DE
8 06-028 (Distribution Rate Case), which included a provision for a transmission
9 cost adjustment mechanism.

10 **Q. Will anyone else be providing testimony in support of this filing?**

11 A. Yes. Jennifer A. Ullram and David J. Burnham are each filing testimony in
12 support of the proposed retail transmission rates. In her testimony, Ms. Ullram
13 will detail the rates applicable to each individual rate class. In his testimony, Mr.
14 Burnham will be providing a description of projects included in LNS rates as well
15 as describing the planning process at ISO-NE.

16 **Q. Describe the types of costs included in this TCAM filing.**

17 A. There are two different groups of costs within this TCAM filing. The first group
18 of costs consists of four cost categories of “wholesale transmission” costs. The
19 second group consists of two cost categories of “other transmission” costs.

20 The “wholesale transmission” costs are as follows:

- 1 1) Regional Network Service (RNS) costs
- 2 2) Local Network Service (LNS) costs
- 3 3) Reliability costs
- 4 4) Scheduling and Dispatch (S&D) costs.

5 All of these costs are regulated by the FERC. These costs are discussed below in
6 more detail.

7 1) RNS costs support the regional transmission infrastructure throughout New
8 England. RNS costs are charged to Eversource by ISO-NE based upon tariffs
9 approved by the FERC. RNS costs are billed to all entities in the region that have
10 RNS load responsibility, such as Eversource, based on their monthly peak load.

11 2) LNS costs encompass Eversource's local transmission costs that are not included in the
12 FERC-jurisdictional RNS tariff. These billings are also governed by FERC
13 approved tariffs and are based on costs allocated to Eversource based on load ratio
14 share¹. Eversource's load ratio share is calculated using a rolling twelve-month
15 coincident peak (12 CP).

16 3) Reliability costs include costs such as Black Start and VAR support that are
17 related to electric reliability. These reliability costs are billed to all entities in the

¹ The wholesale Transmission rate transparency settlement, filed at FERC on June 15, 2020, was approved by FERC on December 28, 2020 in Docket No. ER20-2054-000. Under the Settlement, effective January 1, 2022 Local Service revenue requirements will be billed based on state by state unit rates multiplied times the customer's monthly load, in a manner similar to the RNS rate.

1 region that have RNS load responsibility, such as Eversource, based on their
2 monthly peak load.

3 4) S&D costs are associated with services provided by ISO-NE related to
4 scheduling, system control and dispatch services. These costs are billed by ISO-
5 NE to all entities in the region that have RNS load responsibility, such as
6 Eversource, based on their monthly peak load, in accordance with the applicable
7 FERC tariff.

8 The “other transmission” costs and credits or revenues are as follows:

- 9 A) Hydro-Québec (HQ) Phase I/II support costs and related revenues,
10 B) TCAM working capital allowance return, and
11 C) HQ Interconnection Capacity Credits.

12 Other transmission costs and revenues A) and B) were previously recovered
13 through Eversource’s distribution rates, but were transferred in total or in part to
14 the TCAM for recovery, effective July 1, 2010, as part of a negotiated “Settlement
15 Agreement on Permanent Distribution Service Rates” (“Settlement Agreement”)
16 between Eversource, the Commission Staff, and the Office of Consumer Advocate
17 (OCA) in Docket No. DE 09-035 that was approved in Order No. 25,123. These
18 costs and revenues are discussed below in more detail.

- 19 A) HQ Phase I/II support costs are costs associated with FERC-approved
20 contractual agreements between Eversource and other New England utilities

1 to provide support for, and receive rights related to, transmission and
2 terminal facilities that are used to import electricity from HQ in Canada.
3 Under the amended, extended and restated agreements², Eversource is
4 charged its proportionate share of O&M and capital costs for a twenty-year
5 term that ends on October 31, 2040.

6 Prior to July 1, 2010, Eversource's share of any revenue associated with HQ Phase
7 I/II was returned to customers through the ES rate. Effective July 1, 2010,
8 consistent with the requirements of NHPUC Order No. 25,122, in the 2010 TCAM
9 docket, Docket No. DE 10-158, Eversource began returning its share of any HQ
10 Phase I/II revenues to customers as a revenue credit in the TCAM. That credit
11 continues in the TCAM today³.

² On December 18, 2020 in Docket No. ER21-712-000, the Asset Owners and the IRH Management Committee ("Filing Parties") submitted to FERC for approval an Offer of Settlement ("Settlement") that amended and restated the four Support Agreements and the Use Agreement as part of a comprehensive package that will provide for ongoing financial support of, and related rights and obligations with respect to, the Phase I/II HVDC-TF. The Settlement reflected the exercise by certain IRH of rights under the existing Support Agreements to extend the term of those Support Agreements another twenty years until October 31, 2040. Further, because the Use Agreement by its own terms will remain in effect through expiration of the term of the last Support Agreement, the term of Use Agreement was also extended to October 31, 2040. The Filing Parties asserted that the Phase I/II HVDC-TF are vitally important to both the New England and Québec regions and provide a variety of benefits to consumers in New England. In an order issued on May 20, 2021, FERC accepted the Settlement, finding that it appears to be fair and reasonable and in the public interest. 175 FERC ¶ 61,140 (2020). Materials pertaining to the extension were shared with the Commission, Staff, and OCA in January 2021, and notice of FERC's acceptance of the Settlement was provided to the Commission, Staff, and OCA on May 24, 2021.

³ On April 1, 2021, Public Service Company of New Hampshire ("PSNH") and its affiliates, The Connecticut Light and Power Company ("CL&P") and NSTAR Electric Company ("NSTAR" and together with PSNH and CL&P, "Eversource"), issued a Request for Proposals for the Reassignment of their Use Rights on the Phase I/II HVDC-TF. Proposals were requested for 100% of the Eversource Use Rights or for tranches of their combined Use Rights in bid blocks of 25%, and a fixed dollar proposal was requested. Based on the proposals received, Eversource signed agreements to reassign all of its Use Rights to H.Q. Energy

1 B) When the TCAM was initially approved in Docket No. DE 06-028, there was
2 no provision for a working capital allowance in the TCAM. The TCAM working
3 capital allowance continued to be included with the distribution working capital
4 allowance. As part of the Settlement Agreement, the distribution revenue
5 requirement calculation excluded working capital on transmission costs.
6 Therefore, the TCAM includes a working capital allowance. An updated lead/lag
7 analysis has been completed for rates effective August 1, 2021 based on the
8 lead/lag study discussed later in this testimony.

9 C) HQ Interconnection Capacity Credits were historically included in the Capacity
10 Expense/Credit portion of the ES rate. With the transition from the Eversource-
11 owned generation energy service rates to the new market solicitation rates effective
12 April 1, 2018, it was appropriate to start including these credits in the TCAM, as
13 that is where HQ Phase I/II Support Costs and Revenue Credits currently are
14 included.

15 **Q. Please describe the overall mechanics of the TCAM as they are presented in**
16 **this filing.**

17 A. The TCAM is a mechanism that allows Eversource to fully recover defined FERC
18 and/or Commission approved transmission costs. The proposed TCAM rate is

Services (U.S.) Inc. for a one-year term commencing June 1, 2021. All proceeds from the reassignment of Eversource's Use Rights will be credited back on a pro rata basis to the retail customers of PSNH, CL&P and NSTAR. The forecast proceeds as a result of the RFP for the period June 2021 to July 2022 are shown in Attachment ELM-1, pages 2, 3 and 5, line 19.

1 based on reconciliations of historic transmission costs and forecasted future
2 transmission costs using the latest approved FERC transmission rates.

3 There are two premises that form the basis of the TCAM. First, the TCAM sets
4 transmission rates for a defined future billing period based on transmission cost
5 estimates using current budget and forecast data supported by the latest known
6 FERC approved transmission rates. This future billing period is referred to as the
7 “forecast period”. Second, the TCAM provides all available actual cost and
8 revenue (recovery) data referred to as the “reconciliation period”. Any over- or
9 under-recoveries that are incurred in the reconciliation period are rolled into the
10 subsequent billing period as part of the next TCAM rate.

11 **Q. What is the forecast period used in this filing, and what is the reconciliation**
12 **period?**

13 A. The forecast period in this filing is the twelve-month period August 2021 through
14 July 2022. The reconciliation period includes actual results for January 2020
15 through May 2021 and estimated results for June and July 2021.

16 **Q. Do the transmission rate forecasts contained in this filing reflect the most**
17 **current FERC rates that were to be effective on June 1, 2021?**

18 A. Yes. Please see the table below for the current FERC rates that are proposed for
19 effect on August 1, 2021 and the prior year’s FERC rates approved in DE 20-085:

FERC Approved Rates	Description	DE 21-109		DE 20-085		Change	
		Aug 21 to Dec 21	Jan 22 to Jul 22 **	Aug 20 to Dec 20	Jan 21 to Jul 21	Aug to Dec	Jan to Jul
RNS Rate	\$ per kW per year	\$ 140.98	\$ 143.73	\$ 129.26	\$ 129.26	\$ 11.72	\$ 14.47
	\$ per MWh	\$ 30.39	\$ 30.98	\$ 26.44	\$ 26.44	\$ 3.95	\$ 4.54
LNS Monthly Expense	Load Ratio Share	21.6%	79.0%	20.9%	20.9%	0.7%	58.1%
	Expense	\$ 2,114,000	\$ 2,059,000	\$ 2,045,700	\$ 2,046,000	\$ 68,300	\$ 13,000
	\$ per MWh	\$ 4.05	\$ 4.23	\$ 3.85	\$ 3.85	\$ 0.20	\$ 0.38

** reflects change per the Rate Transparency Settlement approved in Docket No. ER20-2054-000

- 1 **Q. What then, is Eversource proposing as its annual TCAM rate in this filing?**
- 2 A. As shown in Attachment ELM-1, page 1a, Eversource is proposing a forecasted
- 3 average TCAM rate of 2.813 cents/kWh as compared to the current average rate of
- 4 2.758 cents/kWh. The increase in the average TCAM rate is driven primarily by
- 5 an increase in RNS cost of \$16.9M, an increase in LNS costs of \$1.9M, an increase
- 6 in Reliability cost of \$1.6M, a decrease in the forecasted over recovery of \$9.0M, a
- 7 decrease in the forecasted HQ Interconnection Capacity Credits of \$0.9M, a
- 8 decrease in Hydro Quebec Support cost of \$1.5M, an increase in the forecasted
- 9 Revenue Credits of \$7.2M, and decreased other costs of \$1.1M.
- 10 **Q. In Order No. 26,031 (June 28, 2017) in Docket No. DE 17-081, the**
- 11 **Commission noted that there have been changes in the RNS rates as a result**
- 12 **of changes in peak demand throughout New England. In that order, the**
- 13 **Commission noted that as other states in the region reduce their share of peak**
- 14 **load relative to the total, New Hampshire’s share of the peak, and allocation**
- 15 **of costs, increases. The Commission stated that it expected the Company to**
- 16 **explain its efforts to reduce peak demand in New Hampshire in future TCAM**

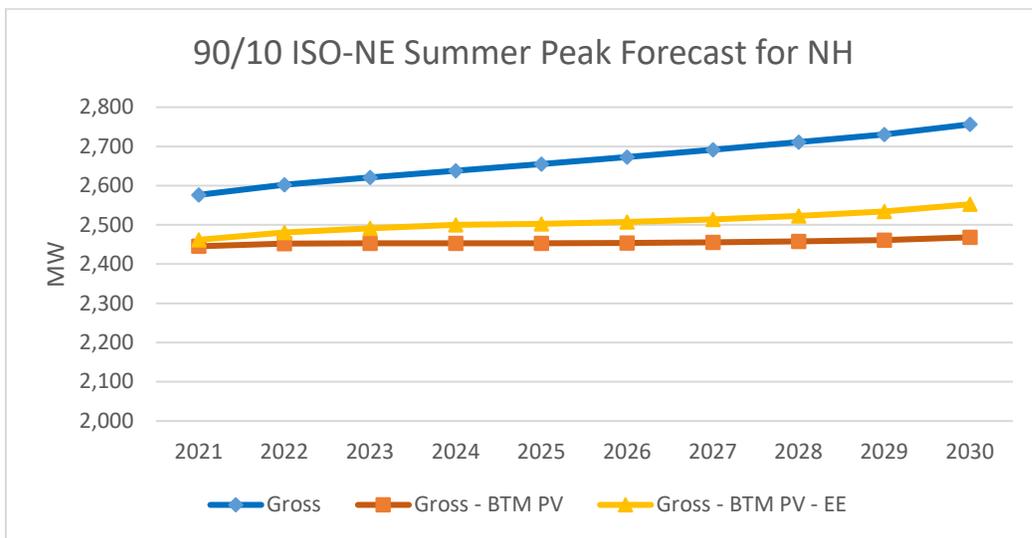
1 **filings. What efforts has Eversource made to address peak demand in New**
2 **Hampshire?**

3 A. As the Company described during the hearing in Docket No. DE 17-081, energy
4 efficiency programs reduce consumption of energy (kWh), and costs, for
5 customers across New Hampshire. The efficiency measures that reduce kWh often
6 also reduce electric demand (kW) at the ISO-NE, distribution and customer level
7 during peak periods. The New Hampshire 3-Year Energy Efficiency Plan per
8 Docket No. DE 17-136 included revised estimates of kW savings for 2020 during
9 ISO-NE summer and winter peak hours. Per the end of year filing the efficiency
10 measures installed in 2020 were estimated to achieve 11.8 MW in summer peak
11 demand reduction and 13.5 MW in winter peak demand reduction. The settlement
12 agreement submitted for Commission approval in Docket No. DE 20-092 for the
13 New Hampshire 3-Year Energy Efficiency plan for 2021-2023 was filed in
14 December 2020 included proposed estimates of kW savings. The efficiency
15 measures proposed for 2021-2023 were estimated to achieve 42.3 MW in summer
16 peak demand reduction and 38.4 MW in winter peak demand reduction⁴. As with
17 the kWh savings, the demand savings will persist over the lifetime of the measures
18 installed. The proposed 3-Year Energy Efficiency plan for 2021-2023 has not yet
19 been approved by the Commission as of the filing of this testimony. In the interim,
20 the Commission has ordered a short-term extension of existing 2020 Energy

⁴ There has been no final Order in DE 20-092 approving the proposed plan. These figures are therefore draft and subject to change based on changes that may be made to savings assumptions, programs and other elements determined by a final Order.

1 Efficiency Programs and System Benefits Charge rates. As a result, budgets for
2 2021 are expected to track closer to those approved for 2020, with savings and
3 peak demand reductions likely lower than those of 2020 due to new realization
4 rates and net-to-gross factors included in the 2021 New Hampshire Technical
5 Reference Manual.

6 ISO-NE has recognized the impact of these energy efficiency measures on its peak
7 demand forecast for New Hampshire, as shown in the below chart⁵:



8
9 As is the case in New Hampshire, the majority of demand savings from energy
10 efficiency programs in the region are achieved as a secondary benefit of the
11 measures designed to generate kWh savings. However, New Hampshire efficiency
12 programs have been monitoring demand management demonstrations and
13 programs taking place in other states to advance tailored methodologies for

⁵ Graphical representation of the 90/10 data contained in the Final 2021 CELT Report published May 1, 2021, using data from the 6.2 Forecasts for Transmission tab.
<https://www.iso-ne.com/system-planning/system-plans-studies/celt>

1 adoption in New Hampshire. The 2018-2020 New Hampshire 3-Year Energy
2 Efficiency Plan includes a section on Capacity Demand Management that
3 describes many of the demand offerings being monitored as viable possibilities to
4 model in state. In 2019 the Company proposed and implemented an active demand
5 reduction offering: the 2019 NH Commercial and Industrial Active Demand
6 Reduction (ADR) Initiative. Results indicated that the 2019 ADR Initiative
7 achieved 3.9 MW in summer peak demand reduction. For 2020 the ADR Initiative
8 was expanded to include residential offerings and results indicate a reduction of
9 12.0 MW in summer peak demand. For the 2021-2023 term, the Company will
10 build upon the demonstrations offered in 2019 and 2020 and explore new active
11 demand reduction offerings during the term. Based upon its success to date, the
12 Company has proposed shifting the Commercial and Industrial demonstration to a
13 full program for the 2021-2023 term. The active demand measures proposed for
14 2021-2023 were estimated to achieve 44.3 MW in summer peak demand reduction.

15 **Q. Has Eversource taken any other direct efforts to reduce peak demand in New**
16 **Hampshire?**

17 A. Yes, Eversource has developed a Commercial and Industrial Demand Reduction
18 Initiative as part of its energy efficiency offerings. This initiative was approved as
19 part of the 2019 Update plan in Docket No. DE 17-136. Under an ADR approach,
20 customers agree to respond to an event call targeting conditions that typically
21 result in peak reductions through curtailment service providers (“CSPs”)—vendors
22 who identify curtailable load, enroll customers, manage curtailment events, and

1 calculate payments. The customer is incentivized to respond to event calls using
2 performance-based incentives. This approach is technology agnostic and can
3 utilize single end-use control strategies or a multitude of approaches that can
4 reduce demand when an event is called. This typically entails customers using
5 lighting with both manual and automated controls, HVAC with both manual and
6 automated controls, process loads, scheduling changes, excess Combined Heat &
7 Power (CHP) capacity, and energy storage to reduce demand. The residential ADR
8 demonstration and proposed program consists of two main bring-your-own-device
9 offerings: Battery Storage and Wi-Fi thermostats. For the 2021-2023 term, the
10 New Hampshire Utilities will also explore electric vehicle (EV) load management
11 as a third offering.

12 **Q. Did Eversource conduct a lead/lag study for the TCAM as required in Order**
13 **No. 25,912, dated June 28, 2016, in Docket No. DE 16-566?**

14 A. Yes, Eversource conducted a lead/lag study for the TCAM and provides that
15 analysis as Attachment ELM-2. The results of the lead/lag analysis will be applied
16 effective August 1, 2021. This lead/lag study methodology is substantially the
17 same as the one provided in Docket No. DE 20-085.

18 **Q. How is cash working capital estimated through a lead-lag study?**

19 A. A lead/lag study identifies the amount of time it typically takes for the Company to
20 collect revenue from customers, as well as the amount of time the Company takes

1 to make payment for applicable operating costs. The difference between those two
2 numbers is used as the basis to estimate cash working capital requirements.

3 **Q. Please describe the lead/lag study completed for the TCAM provided as**
4 **Attachment ELM-2.**

5 A. The Lead/Lag Study consists of 15 pages of calculations and supporting schedules
6 to calculate working capital allowances by month for RNS, S&D, LNS, Reliability,
7 Hydro Quebec Interconnection Capacity Credits (HQ ICC), and HQ support
8 components. Revenue lag days are the same for all components, however expense
9 lead days vary by component. Each component has a separate expense lead days
10 schedule.

11 **Q. Please define the terms “revenue lag days” and “expense lead days.”**

12 A. Revenue lag is the time, measured in days, between delivery of a service to
13 Eversource customers and the receipt by Eversource of the payment for such service.
14 Similarly, expense lead is the time, again measured in days, between the
15 performance of a service on behalf of Eversource by a vendor or employee and
16 payment for such service by Eversource. Since base rates are based on revenue and
17 expenses booked on an accrual basis, the revenue lag results in a need for capital
18 while the expense lead offsets this need to the extent the Company is typically not
19 required to reimburse its vendors until after a service is provided.

1 **Q. How is the retail revenue lag computed?**

2 A. The retail revenue lag consists of a “meter reading or service lag,” “collection lag”
3 and a “billing lag.” The sum of the days associated with these three lag components
4 is the total retail revenue lag experienced by Eversource. See Attachment ELM-2,
5 Page 7 of 15.

6 **Q. What lag does the Lead/Lag Study reveal for the component "meter reading or
7 service lag?"**

8 A. The Lead/Lag Study reveals a lag of 15.2 days. This lag was obtained by dividing
9 the number of billing days in the test year by 12 months and then in half to arrive at
10 the midpoint of the monthly service periods.

11 **Q. How was the “collection lag” calculated and what was the result?**

12 A. The “collection lag” for TCAM totaled 27.2 days. This lag reflects the time delay
13 between the mailing of customer bills and the receipt of the billed revenues from
14 customers. The 27.2-day lag was arrived at by a thorough examination of TCAM
15 accounts receivable balances using the accounts receivable turnover method. End-
16 of-month balances were utilized as the measure of customer accounts receivable.
17 Attachment ELM-2, Page 7 details monthly balances for the majority of the accounts
18 receivable accounts. Attachment ELM-2, Page 7 calculated the average daily
19 revenue amount by dividing total revenue by 365 days. The resulting Collection Lag

1 is derived by dividing the average daily accounts receivable balance by the average
2 daily revenue amount to arrive at the Collection lag of 27.2 days.

3 **Q. How did you arrive at the 1.48 day “billing lag”?**

4 A. Nearly all customers are billed the evening after the meters are read. However, if a
5 meter is read on a Friday or prior to a scheduled holiday, there is additional lag over
6 the weekend or holiday. Consistent with last year’s filing the Company’s billing lag
7 calculation accounts for this additional lag. The updated lead/lag study uses a 1.48-
8 day billing lag as shown in Attachment ELM-2, Page 9. An exception for large
9 customers which may require additional time to process has not been made in this
10 calculation.

11 **Q. Is the total retail revenue lag computed from these separate lag calculations?**

12 A. Yes. The total retail revenue lag of 43.9 days is computed by adding the number of
13 days associated with each of the three retail revenue lag components. See,
14 Attachment ELM-2, Page 7. This total number of lag days represents the amount of
15 time between the recorded delivery of service to retail customers and the receipt of
16 the related revenues from retail customers.

17 **Q. Please explain how the RNS, S&D, LNS, Reliability, HQ expenses, and HQ
18 ICC lead/lag period is determined.**

19 A. The monthly payments were reviewed and the expense lead days were calculated
20 based on the actual payment date of the payments. Once the lead days for each

1 category were determined, they were summarized and dollar weighted according to
2 2020 actual annual amounts to arrive at the lead days. These calculations are shown
3 in Attachment ELM-2, pages 10 through 15.

4 **Q. Please explain how the Eversource Energy Service Company (EESC) due date**
5 **is determined related to LNS billings.**

6 A. Per the terms of the Service Contract between the Company and EESC, bills are
7 rendered for each calendar month on or before the twentieth day of the succeeding
8 month and are payable upon presentation and not later than the last day of that
9 month.

10 **Q. Has the Company included an expense lead for the 2019 LNS true-up amount**
11 **that was accounted for in July 2020? If so, please explain how the expense**
12 **lead is determined relative to 2019 LNS true-up amount compared to the**
13 **current month LNS billing in July 2020.**

14 A. Yes. As shown in Attachment ELM-2, Page 12, the expense lead for the prior year
15 2019 LNS true up under recovery is determined by calculating the number of days
16 from the mid-point of the true-up year (in this case 2019) to the payment date. This
17 results in a longer expense lead compared to the current month LNS billing that is
18 paid on the same day.

1 **Q. Please explain how the change in RNS rates impacts the Company's proposed**
2 **revenue requirement.**

3 A. The RNS rate effective June 1, 2021 and January 1, 2022 increased as compared to
4 the prior RNS rate due to forecasted incremental investments in transmission
5 infrastructure. The TCAM thus reflects higher RNS costs attributable to the
6 Company in accordance with applicable FERC-approved tariffs.

7 **Q. Would you summarize the Company's proposal regarding Cash Working**
8 **Capital?**

9 A. Based on the results of the lead/lag analysis of Eversource TCAM Cash Working
10 Capital, the Company identified an RNS working capital component of (19.4)
11 days, or (5.32) percent, an S&D working capital component of (19.4) days, or
12 (5.32) percent, an LNS working capital component of (131.4) days, or (35.99)
13 percent, a Reliability working capital component of (19.4) days, or (5.31)
14 percent, an HQ Expense working capital component of 44.7 days, or 12.24
15 percent, and an HQ ICC working capital component of (19.5) days or (5.35)
16 percent. Application of these values results in a total forecasted cash working
17 capital allowance of (\$20.346) million and a forecasted return on working capital
18 of (\$1.780) million for the forecasted period of August 2021 through July 2022.

1 **Q. Does Eversource require Commission approval of this rate by a specific date?**

2 A. Yes, Eversource is requesting final approval of the proposed TCAM rate change

3 by July 26, 2021 to allow for the implementation of an August 1, 2021 change in

4 rates.

5 **Q. Does this conclude your testimony?**

6 A. Yes, it does.