

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

JOINT REBUTTAL TESTIMONY OF

**Edward A. Davis, Brian J. Rice, Dawn Coskren, Joseph
Swift and Colleen Bennett on behalf of PUBLIC
SERVICE COMPANY OF NEW HAMPSHIRE d/b/a
EVERSOURCE ENERGY**

**Karen M. Asbury, John J. Bonazoli, and Jeff Pentz on behalf of UNITIL ENERGY
SYSTEMS, INC. D/B/A UNITIL, INC.**

and

**Robert Garcia, Dilip K. Kommineni and Laura Sasso on behalf of LIBERTY UTILITIES
(GRANITE STATE ELECTRIC) CORP. D/B/A LIBERTY**

**CONSIDERATION OF CHANGES TO THE CURRENT NET METERING TARIFF
STRUCTURE, INCLUDING COMPENSATION OF CUSTOMER-GENERATORS**

Docket No. DE 22-060

January 30, 2024

I. INTRODUCTION & QUALIFICATIONS

1 **Q. Mr. Davis, please state your name, business address and position.**

2 A. My name is Edward A. Davis. My business address is 107 Selden Street, Berlin, CT
3 06037. My position is Director, Rates at Eversource Energy Service Company and in that
4 position I provide rate and tariff related services to the operating companies of
5 Eversource Energy including Public Service Company of New Hampshire d/b/a
6 Eversource Energy (“Eversource” or “the Company”).
7

8 **Q. Have you previously testified before the New Hampshire Public Utilities
9 Commission (“Commission”)?**

10 A. Yes. I have on many occasions testified before the Commission on behalf of Eversource,
11 and at the state utility commissions in Connecticut and Massachusetts on behalf of other
12 Eversource Energy affiliates on rate related matters.
13

14 **Q. Have you previously submitted testimony in this proceeding?**

15 A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with
16 other Eversource witnesses as well as Unitil and Liberty witnesses. In that testimony, I
17 summarize my educational and professional background.
18

19 **Q. Mr. Rice, please state your name, business address and position.**

20 A. My name is Brian J. Rice. My business address is 247 Station Drive, Westwood, MA
21 02090. My position is Director, Customer Solar Programs at Eversource Energy Service

1 Company and in that position I provide oversight of solar programs for Eversource
2 customers in multiple New England states.

3
4 **Q. Have you previously testified before the Commission?**

5 A. Yes. I have on many occasions testified before the Commission on behalf of Eversource,
6 and at the state utility commissions in Connecticut and Massachusetts on behalf of other
7 Eversource Energy affiliates on rate related matters.

8
9 **Q. Have you previously submitted testimony in this proceeding?**

10 A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with
11 other Eversource witnesses as well as Unitil and Liberty witnesses. In that testimony, I
12 summarize my educational and professional background.

13
14 **Q. Ms. Coskren, please state your name, business address, company position, and
15 principal responsibilities in your current position.**

16 A: My name is Dawn Coskren, I work at 73 West Brook Street in Manchester, New
17 Hampshire. I work for Eversource Energy Service Company as Manager for Billing and
18 Data Management for PSNH and Eversource Energy's affiliate in Western
19 Massachusetts. In this role I'm responsible for managing activities associated with
20 billing and meter data management of Eversource Energy and establishing practices to
21 ensure that accurate bills are issued in a timely manner.

22

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

2 A. Yes. I have on many occasions testified before the Commission on behalf of Eversource,
3 and at the state utility commissions in Connecticut and Massachusetts on behalf of other
4 Eversource Energy affiliates on rate related matters.

5

6 **Q. Have you previously submitted testimony in this proceeding?**

7 A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with
8 other Eversource witnesses as well as Unitil and Liberty witnesses. In that testimony, I
9 summarize my educational and professional background.

10

11 **Q. Ms. Bennett, please state your name, business address, company position, and
12 principal responsibilities in your current position.**

13 A: My name is Colleen Bennett, I work at 107 Selden Street, Berlin, CT 06037. My position
14 is Manager, Load Settlement and Analysis, at Eversource Energy Service Company and
15 in that position I provide load settlement and load research services to the operating
16 companies of Eversource Energy including Public Service Company of New Hampshire
17 d/b/a Eversource Energy (“Eversource” or “the Company”).

18

19 **Q. Please describe your educational background and professional experience.**

20 A. I graduated from the University of Hartford in 2004 with Bachelor of Science in Business
21 Administration from the University of Hartford. After interning with the company since
22 2001 in Finance and Business Performance at the affiliate Northeast Generation Services,

1 I joined the load research department at Northeast Utilities full time upon graduation. I
2 held various roles in load research with increasing responsibility until July 2022 when I
3 was named to my current position, adding load settlement to my area of responsibility.
4

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

6 A. No I have not.
7

8 **Q. Mr. Swift, please state your name, business address, company position, and
9 principal responsibilities in your current position.**

10 A: My name is Joseph Swift, I work at 107 Selden Street, Berlin, CT 06037. My position is
11 Supervisor, Load and Settlement Planning and Operations, at Eversource Energy Service
12 Company and in that position I provide load settlement services to the operating
13 companies of Eversource Energy including Public Service Company of New Hampshire
14 d/b/a Eversource Energy (“Eversource” or “the Company”).
15

16 **Q. Please describe your educational background and professional experience.**

17 A. I have worked at Eversource for 24 years in Energy Efficiency and Load Settlement. I
18 have a Bachelor of Science Degree in Mechanical Engineering from the University of
19 Rhode Island and a master’s degree in Power Systems Engineering from Worcester
20 Polytechnic Institute.
21

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

23 A. Yes I have. I provided information to the Commission on the benefit-cost methodology

1 used for the 2018-2020 Statewide Energy Efficiency Plan in Docket No. DE 17-136.

2
3 **Q. Ms. Asbury, please state your name, business address and position.**

4 A. My name is Karen M. Asbury. My business address is 6 Liberty Lane West, Hampton,
5 New Hampshire 03842. I am the Director of Regulatory Services for Unitil Service
6 Corp. which provides centralized management and administrative services to all Unitil
7 Corporation's affiliates including Unitil Energy Systems, Inc.

8
9 **Q. Have you previously testified before the Commission?**

10 A. Yes. I have testified before this Commission and the Massachusetts Department of Public
11 Utilities on behalf of Unitil and its affiliates.

12
13 **Q. Have you previously submitted testimony in this proceeding?**

14 A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with
15 other Unitil witness as well as Eversource and Liberty witnesses. In that testimony, I
16 summarize my educational and professional background.

17
18 **Q. Mr. Bonazoli, please state your name, business address and position.**

19 A. My name is John J. Bonazoli. I am the Manager of the Distribution Engineering
20 Department for Unitil Service Corp. which provides centralized management and
21 administrative services to all Unitil Corporation's affiliates including Unitil Energy
22 Systems, Inc.

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

2 A. Yes. I have testified before the Commission and the Massachusetts Department of Public
3 Utilities on behalf of Unitil and its affiliates.

4
5 **Q. Have you previously submitted testimony in this proceeding?**

6 A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with
7 other Unitil witness as well as Eversource and Liberty witnesses. In that testimony, I
8 summarize my educational and professional background.

9
10 **Q. Mr. Pentz, please state your name, business address and position.**

11 A. My name is Jeffrey M. Pentz. I am the Supervisor, Energy Supply for Unitil Service
12 Corp. which provides centralized management and administrative services to all Unitil
13 Corporation's affiliates including Unitil Energy Systems, Inc.

14
15 **Q Please describe your educational background and professional experience.**

16 A. I received my Bachelor of Arts degree in Economics from the University of
17 Massachusetts. Before joining Unitil, I worked as a Contracting and Transaction Analyst
18 with Mint Energy, a retail electric supplier. My range of responsibilities included contract
19 negotiation with brokers and customers, retail billing, and sales. Prior to Mint Energy, I
20 worked as a data analyst for Energy Services Group. My responsibilities included
21 supplier business transaction testing and integration with regulated utilities. I joined
22 Unitil Service Corp. in February 2016. I have primary responsibilities in the areas of

1 default service procurement, renewable energy credit procurement and renewable
2 portfolio standard compliance, load settlement, market research and operations, and
3 monitoring renewable energy policy.

4
5 **Q. Have you previously testified before the Commission?**

6 A. Yes. I have testified before the Commission and the Massachusetts Department of Public
7 Utilities on behalf of Unitil and its affiliates.

8
9 **Q. Mr. Kommineni, please state your name, business address and position.**

10 A. My name is Dilip K. Kommineni. My business address is 9 Lowell Road, Salem, NH
11 03079 and I am employed as the Sr. Manager of Engineering by Liberty Utilities Service
12 Corp. (“LUSC”), which provides services to Liberty Utilities (Granite State Electric)
13 Corp. (“Liberty”).

14
15 **Q. Have you previously submitted testimony in this proceeding?**

16 A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with
17 other Liberty witness as well as Eversource and Unitil witnesses. In that testimony, I
18 summarize my educational and professional background.

19
20 **Q. Ms. Sasso, please state your name, business address and position.**

21 A. My name is Laura Sasso. I am employed by LUSC as a Senior Manager, Billing, East
22 Region, providing services to the Liberty affiliates in the East Region, including Liberty.

1 My office address is 15 Buttrick Road, Londonderry, New Hampshire. I have been with
2 Liberty for 11 years and have been in the industry for 27 years.

3

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

5 A. Yes, I filed testimony in Docket No. DE 23-063, the Joint Utilities' Petition for Waiver of
6 Certain Provisions of the Puc 2200 Rules.

7

8 **Q. Have you previously submitted testimony in this proceeding?**

9 A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with
10 other Liberty witness as well as Eversource and Unitil witnesses. In that testimony, I
11 summarize my educational and professional background.

12

13 **Q. Mr. Garcia, please state your name, business address, company position, and
14 principal responsibilities in your current position.**

15 A. My name is Robert Garcia. My business address is 15 Buttrick Road, Londonderry, New
16 Hampshire. My title is Manager, Rates and Regulatory Affairs. As Manager of Rates
17 and Regulatory Affairs, I am primarily responsible for rate administration and regulatory
18 affairs for Liberty EnergyNorth and Liberty Utilities (Granite State Electric) Corp.

19

20 **Q. Please describe your educational background and professional experience.**

21 A. I have an Artium Baccalaureus (Bachelor of Arts) degree in Political Science and French
22 from Wabash College (Crawfordsville, Indiana) and a Master of Public Administration

1 degree from the School of Public and Environmental Affairs at Indiana University
2 (Bloomington, Indiana) with concentrations in Policy (Quantitative) Analysis and
3 International Affairs. I also obtained a Certificat De Langue Et Civilisation Française
4 from the Université de Paris – Sorbonne (Paris, France) and, as part of my graduate
5 studies, studied French and European government at the École Nationale
6 D'Administration (Paris, France).

7 I was employed by ComEd from April 2001 to March 2023. I began my employment
8 with ComEd in the Regulatory Department as a Regulatory Specialist and moved on to
9 the positions of Senior Regulatory Specialist in 2004, Manager of Regulatory Strategies
10 and Solutions in 2008, and Director of Regulatory Strategy and Services in 2013 before
11 assuming my last position as Director of Regulatory Innovation & Initiatives in 2021.

12 Prior to joining ComEd, I worked for nearly nine years at the Illinois Commerce
13 Commission, beginning in 1992 as an intern in what was then the Office of Policy and
14 Planning and ending in 2001 as the senior policy advisor to a Commissioner. I initially
15 joined the Commission Staff through the James H. Dunn Memorial Fellowship program,
16 a one-year program sponsored by the Office of the Governor. Through this Fellowship, I
17 also held short-term positions in the Bureau of the Budget and the Governor's Legislative
18 Office.

19 **Q. Have you previously testified before the New Hampshire Public Utilities**
20 **Commission?**

21 **A.** Yes, I have.

1 **Q. What is the purpose of this joint rebuttal testimony?**

2 A. The purpose of Eversource, Unitil, and Liberty’s (the “Joint Utilities”) rebuttal testimony
3 is to address various proposals made by parties to this docket submitted in testimony filed
4 on December 6, 2023.

5

6 **Q. How is this rebuttal testimony organized?**

7 A. Our rebuttal begins by endorsing certain parties’ support of sustaining grandfathering for
8 existing net metering customers. We then discuss various proposed adjustments to the
9 current compensation levels and structure of net metering credits. This is followed by a
10 discussion of the implications of Community Power Coalition of New Hampshire’s
11 (“CPCNH”) proposal involving accounting for unregistered customer energy exports as a
12 reduction to the Joint Utilities’ competitive suppliers’ wholesale load obligation. We
13 briefly assess the Office of the Consumer Advocate’s (“OCA”) central recommendations,
14 and our testimony concludes by presenting the Joint Utilities’ proposal for
15 interconnection application fees.

16

17 **II. GRANDFATHERING**

18 **Q: Clean Energy New Hampshire (“CENH”) proposes a 20-year term for**
19 **grandfathering existing projects that are currently assigned to either of the two net**
20 **metering tariffs, and the CPCNH likewise supports grandfathering. Do the Joint**
21 **Utilities have a position on this issue?**

22 A: The Joint Utilities appreciate the reasoning for grandfathering as proposed by CENH,

1 which after clarifying discussions at docket technical sessions, we understand to mean a
2 20-year term from the time each project begins net metering, *not* when the project
3 interconnects to the grid. If a net metering customer wishes to move to a newer tariff,
4 they may do so, but they cannot return to their original tariff. The 20-year term as
5 proposed by CENH provides stability to the distributed generation (“DG”) industry and
6 to the regulatory community. The Joint Utilities agree with this policy objective, but we
7 note that it will be difficult to implement and enforce through a project-specific policy.
8 Currently, the interconnection application process and Joint Utility billing systems do not
9 have the functionality to track when a system comes online and start a 20-year clock. We
10 support the concept of grandfathering but would recommend a standardized term that the
11 Joint Utilities can implement without incurring incremental costs or complexity, which
12 would strike the balance of allowing for the evolution of net metering compensation
13 while ensuring market stability by “serv[ing] to preserve the value of the investments
14 [net-metered customer-generators] have made in DG systems.” (Order No. 26,047 at 12
15 (August 18, 2017)).

17 **III. ADJUSTMENTS TO COMPENSATION**

18 **Q: CENH and CPCNH suggest altering current net metering compensation in various**
19 **ways. Do you have any general impressions regarding such proposals or comments**
20 **on specific proposals?**

21 **A:** As a general matter we understand the desire to adjust compensation to preserve or
22 expand the accessibility of clean energy options for New Hampshire customers. The

1 Joint Utilities are also interested in maximizing the choices our customers have to meet
2 their energy needs. Our concern remains the same as it was articulated in our original
3 testimony in this docket – that any upward adjustment to credit for excess generation
4 risks shifting costs to non-net metered customers as larger credits and expanded
5 participation would increase overall program costs borne by all customers. Assertions
6 that the revenues and customers benefits produced by distributed generation (“DG”) are
7 commensurate with proposed credits remain, to various degrees, based on assumptions
8 and estimates that are ultimately difficult to validate. A compensation structure that
9 remains weighted toward values that can be most readily measured and quantified will
10 continue to support customer choices while mitigating the risk of cost shifting. The Joint
11 Utilities believe energy values can be readily quantified and validated based on wholesale
12 market prices and meter data and, as such, customers should continue to be credited for
13 excess generation based upon the prevailing default energy service rate.

14
15 Long-term reductions in distribution and transmission system investment and operating
16 expenses associated with deployment of DG will depend on the location of each DG
17 project and the performance of those assets over time. Many DG projects will not
18 meaningfully reduce or avoid expenses to operate the electric power system and may in
19 fact result in additional costs for system upgrades and operating requirements. The Joint
20 Utilities believe the current net metering tariff appropriately limits the inclusion of
21 transmission and distribution values in credit for surplus generation to only the smallest
22 projects which, by virtue of their size, are more likely to provide an incremental impact

1 on loaded circuits and be distributed throughout a utility's service territory. Expanding
2 credit based on transmission and distribution rates, both in magnitude and the scope of
3 eligible projects, risks crediting projects for value that they may be less likely to realize.

4
5 CENH's proposal to include a one-cent adder for west facing solar is technically possible
6 to implement but unfortunately cumbersome to enforce. Compensation based on the
7 direction panels are facing would require a process to confirm the direction, which in turn
8 would require a site visit to verify and consequently could delay the application process
9 for the customers with west-facing panels as well as other customers in the
10 interconnection queue. The west-facing adder would also create some degree of new
11 administrative and billing costs associated with tracking the direction of each customer's
12 panels and establishing separate credits in the applicable systems and equipment.

13 Conceptually, the criteria for "west-facing" would also need to be more clearly defined.

14 For example, it is unclear how a home with fixed panels facing both south and west
15 (within the 225 to 315 degrees azimuth range proposed by CENH) would be credited
16 under this proposal. Depending on the type of solar installation (*e.g.*, pedestal), the
17 policy purpose of the adder also could be circumvented to take advantage of the credit by
18 pointing southwest (225 degrees azimuth) initially and moving the direction of the panel
19 due south after any utility inspection. This adder also runs the same risk of slowing down
20 the application process due to verification requirements.

21
22

1 CENH also proposes to increase surplus generation credit for large customers (projects
2 over 100kW) to include up to 50 percent of the transmission kWh rate and 50 percent of
3 the distribution kWh rate. The surplus generation for small projects up to 100kW is also
4 proposed to increase by inclusion of 50 percent of the distribution kWh rate, up from 25
5 percent. The CENH proposal would likely support further growth of distributed
6 generation in New Hampshire as more customers would be able to cost-effectively install
7 renewable energy by virtue of receiving increased credit for their excess generation.
8 However, implementation of the proposal would also likely increase the level and risk of
9 costs being shifted to other customers.

10
11 CPCNH has proposed numerous changes to compensation including: reducing the energy
12 supply portion of the credit to essentially that of the competitive supplier's bid price to
13 supply default energy service (eliminating RPS compliance and line loss); making all
14 DG-connected storage eligible for compensation including storage charged from the grid;
15 addition of credit for "actual avoided transmission costs" – for those projects with
16 interval meters, and individual bespoke credit based on meter data, and for projects
17 without meters one blanket credit amount – for all large projects over (100kW); and
18 adding compensation for avoided capacity costs.

19
20 Taking these recommendations in order, reducing the supply credit to eliminate the
21 component associated with RPS costs and a designated line loss adjustment factor would
22 be feasible and would lower the costs of utility net metering that might otherwise result

1 by reducing overall supply credits paid out. This would also create two different supply
2 rates for net metered customers: one applicable to supply and the other applicable to
3 customer exports. The full supply rate would be billed on net usage, and a different,
4 lower rate would be credited for net generation. The Joint Utilities would incur some
5 implementation costs for billing systems to credit at a different rate. But our larger
6 concern is that having two different supply rates on one bill would risk creating customer
7 confusion and make it more difficult for net metered customers to understand their bill if
8 multiple supply rates are used. The Joint Utilities recommend preserving the
9 administrative and customer efficiencies associated with crediting customers at the same
10 supply rate they are billed.

11
12 And to clarify a factual matter in response to the assertion in CPCNH's testimony that
13 there is no basis to include RPS compliance costs in the net metering credit, it is true that
14 the bulk of the difference between the full default service rate and what the supplier is
15 paid is mainly the cost of RPS compliance, which is calculated on utility MWh sales.
16 However, there is a credit adjustment percentage that is released by the DOE in February
17 each year that reduces the RPS obligation each utility owes through a credit to Class I and
18 Class II Renewable Energy Certificates ("RECs") based on the capacity of net metered
19 facilities that are not certified to produce Class I or Class II RECs, pursuant to RSA 362-
20 F:6, II-a and Puc 2503.04(d). The RECs that Eversource receives from facilities that are
21 on Eversource's Group Host Program, for example, are not certified for use, which
22 therefore contributes to the credit from the DOE and reduces the RPS expense.

1 CPCNH's testimony cites an RPS adder of \$0.00834, but it does not include the
2 corresponding DOE RPS adder credit of \$0.00607 which nets to \$0.00227. The netted
3 amount should be the basis for CPCNH's hypothetical cost examples rather than the
4 \$0.00834. There is also a comment in CPCNH testimony on Page 25, row 21 that the
5 RPS reconciliation credit is unusually large. That is because the referenced credit
6 includes the adjustment made to the Class III REC obligation made in April after the
7 reporting year has concluded. For added context and clarification, the DOE has the
8 option to ratchet down the Class III REC obligation for Load Serving Entities each year.
9 And though it is optional, the DOE (and previously PUC through PUC staff) have
10 exercised that option every year since 2008 except 2017-2019, and every year that
11 reduction is pronounced down from the required eight percent to usually two percent or
12 less. Ultimately, removing the RPS added from the net metering credit would be a
13 negligible change in compensation, but would add significant complexity to
14 compensation administration and to customers understanding their bills.

15
16 Making DG-connected storage eligible for net metering credits raises some questions. As
17 an initial matter, the net metering statutory provisions and Puc 900 rules allow only
18 customers generating electricity using renewable energy sources to be eligible for net
19 metering. RSA 362-A:1-a, II-b and Puc 902.05 define an "eligible customer generator"
20 as "an electric customer who owns, operates, or purchases power from an electrical
21 generating facility either powered by renewable energy or which employs a heat led
22 combined heat and power system." Batteries do not fit within this definition of

1 “generator”. Furthermore, there is concern about customers charging their batteries from
2 the grid instead of using their solar. Puc 902.05 requires any discharge to the distribution
3 system be from renewable energy. While customers participating in Liberty’s battery
4 pilot were allowed to charge from the grid and receive credits when paired with solar, the
5 Commission made it clear that this was only permitted because Liberty, not the customer,
6 discharged the battery per pilot study parameters, which was for the specific and narrow
7 purpose of offsetting predicted system peaks. Order No. 26,784 at 5-6, Docket No. DE
8 17-189 (March 15, 2023). So the policy purpose behind credit afforded customers in the
9 Liberty pilot is not analogous to simply making all battery storage eligible for net
10 metering credits, particularly if there are no checks on customer charging and discharging
11 behavior. Liberty’s control over discharging the battery ensured the battery was only
12 used for the pilot’s policy purpose. In contrast, there is little the Joint Utilities can do to
13 ensure customers are not going to charge batteries from the grid, discharge to the grid,
14 and then receive credit for that discharge erodes the policy objectives of net metering.
15 The Joint Utilities therefore recommend that this proposal not be adopted at this time, or
16 not without substantial qualifications or limitations on eligibility and application.

17
18 Also pertaining to battery storage is the related proposal by CENH to provide a two-cent
19 adder for battery storage paired with DG, which unfortunately suffers from the same
20 infirmity of enforceability. Namely, there is no efficient way to police customers with
21 solar and storage to ensure they are not charging the storage with grid power and then
22 discharging the storage to the grid. Efforts to do so will again add costs associated with

1 site visits and potentially disrupt the interconnection queue, in addition to any
2 incremental billing and other tracking costs to implement the adder. Lastly, it is unclear
3 whether a two-cent adder, even if limited to a battery charged by a resource that qualifies
4 for net metering, would materially change the economics of a battery investment and
5 induce battery adoption by net metering customers. Thus, while there is certainty that
6 costs will be incurred by the Joint Utilities to implement such an adder, there is no
7 certainty that it would achieve the policy objective of expanding storage resources in the
8 State.

9
10 The Joint Utilities have both practical and policy concerns with the CPCNH proposal that
11 customers be compensated for avoided Regional Network Service (“RNS”) charges.
12 Implementation of the CPCNH proposal would risk crediting customer-generators
13 amounts that significantly exceed any potential benefits that might be ultimately realized
14 for utility customers and would further increase costs through expansion of utility
15 administrative requirements.¹

16
17 As an initial practical matter, the CPCNH proposal would increase the costs incurred by
18 the Joint Utilities to administer net metering tariffs by requiring monthly, individual
19 calculations of transmission credit based on interval data for those customer-generators
20 with interval meters. Such a process would be a significant departure from preferred bulk

¹ The Joint Utilities also note that the CPCNH proposal may implicate federal jurisdictional issues regarding wholesale reassignments or sales of transmission service and potential “cost-trapping” of charges assessed based on FERC-approved transmission rates, as described in their submissions in Docket No. DE 23-026. *See* Joint Utilities’ Initial Brief at 14-20; Joint Utilities’ Reply Brief at 17-22; both as filed in Docket No. DE 23-026.

1 billing processes that efficiently support service to a high volume of customers. The
2 CPCNH proposal that additional load profiles be derived for non-interval metered
3 customers would also expand utility responsibilities and require considerable data and
4 analysis.

5
6 More importantly, the CPCNH proposal appears based on incomplete analysis that
7 equates charges assessed to utilities as regional network customers and then as costs
8 charged to New Hampshire customers through operation of ISO-NE transmission tariffs
9 with the actual costs incurred to build, maintain and operate the electrical transmission
10 system for New Hampshire customers. These values are not the same, and it is important
11 that their differences be recognized in the design of any net metering credit structure.

12 The RNS costs referenced in the CPCNH proposal are shared regional costs *allocated* to
13 New Hampshire customers (through their utilities as network customers) on the basis of
14 each New Hampshire utility's proportional share of New England's peak load each
15 month. Apportioning the costs of the regional transmission system on the basis of peak
16 load is an efficient and reasonable method for recovering costs fairly from all New
17 England customers, but it does not provide a price signal for actual transmission cost
18 avoidance that should be incorporated into New Hampshire's net metering tariff. The
19 RNS charges that result from this allocation method represent the total *average cost* of
20 the regional transmission system expressed in \$/kW and reflecting the regulated cost of
21 service of the transmission system. Wholesale energy and capacity prices, on the other
22 hand, reflect the *marginal cost* of competitively bid generating resources required to

1 satisfy regional energy and generating capacity requirements. Actual transmission
2 system costs are also not exclusively correlated with regional peak load. A significant
3 portion of transmission investment and operating expense is driven by asset condition and
4 reliability requirements. Even when transmission investments are made to address
5 increased load, those investments are planned to address loading periods that extend
6 beyond a single peak hour, and which may vary from regional peak periods. As a result,
7 a net metering tariff that fully credits net metering customers for transmission charges on
8 the basis of coincident peak load would likely credit customers for costs of the regional
9 transmission system that have already been incurred and are unlikely to be avoided
10 through peak load reduction.

11
12 The Joint Utilities recommend that the Commission decline to expressly credit customer-
13 generators for allocated transmission costs as proposed by CPCNH for the reasons
14 outlined above, but potential transmission system benefits should still be considered in
15 this proceeding. The VDER study appropriately sought to assess potential transmission
16 value based on the best available information. The Commission can reasonably expect
17 that distributed generation is likely to have some aggregate beneficial impact on
18 transmission costs that offsets the costs of net metering credits, even if that value cannot
19 be precisely quantified and is likely much less than the value CPCNH proposes be
20 credited to customer-generators.

1 Finally, the Joint Utilities note, as we did in our original testimony, that the default
2 service supplier bid price includes costs for capacity, so customers are already receiving
3 capacity credit through the energy supply portion of the current net metering tariff.
4 CPCNH also proposes changes to the calculation of capacity obligations for competitive
5 and default service suppliers which are discussed in the following section.

6
7 **IV. ACCOUNTING FOR EXPORTS TO THE GRID BY MODIFYING LOAD**
8 **SETTLEMENT**

9 **Q: CPCNH recommends that utility default service customers' energy exports to the**
10 **grid moving forward are accounted for as a reduction in the wholesale load**
11 **obligation of the utilities' respective suppliers. What changes does this implicate**
12 **and what would those changes entail?**

13 A. To account for energy exports to the grid that are not registered with ISO-NE, the Joint
14 Utilities would have to make fundamental changes to how we settle load with ISO-NE.
15 Currently, load settlement is done uniformly throughout the ISO-NE territory, so if New
16 Hampshire were to change its process, it would be anomalous in the region. Adjusting
17 the load settlement process is a matter of significant complexity that would take
18 substantial time and resources to implement, as outlined in Liberty and Eversource's joint
19 response to CENH data request 3-002, included with this testimony as Attachment A, and
20 with which Unitil concurs. As stated in that response, numerous factors contribute to the
21 time and resources that would need to be dedicated even to exploring this change: the
22 implications to the whole of the New Hampshire competitive supplier community will

1 necessitate a working group to reach consensus on any changes; and the load settlement
2 systems of the Joint Utilities are enterprise-wide systems not dedicated exclusively to
3 New Hampshire. This unfortunately slows any changes, because changes to these
4 systems must wait in a larger queue and are inherently complex because it will be a New
5 Hampshire-only change to a uniform, multi-state process.

6
7 Even without having completed actual cost estimates, the Joint Utilities can state with
8 confidence that the proposed change to load settlement would be a seven-figure
9 investment that would easily take two years, likely more, to complete. CPCNH's
10 proposal did not state from whom the costs of these changes would be recovered—we
11 assume that it would be from all customers—and it is unclear which customers would
12 ultimately see benefits from this change. The proposed change would provide a
13 relatively small reduction to suppliers' wholesale load obligation, and only for those
14 suppliers that have disproportionately high penetration of behind-the-meter generation.
15 And the reduction does not represent pure savings. Any savings seen by one supplier
16 would have to be offset by increases to remaining suppliers that have disproportionately
17 lower penetration of behind-the-meter generation. Costs shift from one supplier to
18 another because overall, total load obligations remain the same across the whole of each
19 utility's meter domain; in other words, the same amount of dollars is due to ISO-NE,
20 regardless of the change to load settlement methodology, meaning there are no net
21 savings, just a different allocation of costs.

22

1 As an additional matter, suppliers that provide utility default service bid an all-in rate –
2 there is nothing that would require them, or any other competitive supplier, to pass on
3 any savings they may receive (and it is unclear how much savings, if any, there will be)
4 to utility default service customers or any other customers, or aggregations, they serve.
5 Furthermore, for the utility to offset net metering credit costs by building a requirement
6 to pass along any potential savings from adjustments to load settlement into default
7 service RFPs would likely have a detrimental effect on the number and competitiveness
8 of bids received for those RFPs, due to the likely reluctance of suppliers wanting to agree
9 to this without knowing what the implications would be. So ultimately, for multiple
10 reasons, the actualization of tangible benefits to customers, particularly once accounting
11 for the costs to implement, is speculative.

12
13 Of significant concern is that the recommendation to modify the load settlement process
14 entails an extensive effort with many moving pieces and ripple effects for many entities,
15 most of which are not parties to this docket. If the Joint Utilities were to modify how
16 they settle load for default service energy suppliers, load settlement would have to be
17 modified across the board for all suppliers in New Hampshire, for several reasons. First,
18 load settlement is administered pursuant to the Joint Utilities' tariffs, which must be
19 applied uniformly; and to apply different methods for load settlement ad hoc would be
20 fundamentally unfair to suppliers who do business in the state. And as a practical matter,
21 a single method for settling load is the only feasible way to execute load settlement. So
22 these changes are really implicating the New Hampshire supplier community as a whole,

1 and as such the supplier community should have an opportunity to weigh in on a topic
2 that would directly and significantly impact their business.

3
4 When combining the repercussions discussed above to the considerable costs attendant to
5 the proposed modification to the load settlement process, costs that have a high level of
6 uncertainty regarding commensurate benefits, we do not support adopting this
7 recommendation to apply to utility default service energy suppliers. The Joint Utilities
8 refrain from commenting on the merits of applying these changes to enable community
9 power aggregation (“CPA”) net metering, as that is a different question with distinct
10 issues that are outside the scope of this docket and thus must be addressed in a dedicated
11 proceeding of its own; and in any event, adjusting the load settlement process should be
12 addressed in a separate proceeding to provide notice of the issue to all appropriate and
13 potentially affected parties. Relatedly, we note that neither the rule cited to in CPCNH’s
14 testimony, Puc 2205.15, nor the statutory provision of RSA 362-A:9, II, contain any
15 compliance obligation of the Joint Utilities as they are enabling provisions allowing
16 CPAs to offer net metering credit programs. Therefore, there are no compliance
17 implications in this docket.

18
19 However, before concluding the discussion of accounting for unregistered generation of
20 net metered customers, we would like to mention the merit in a possible alternative to
21 changing the load settlement process. Developing load profiles for net metered
22 customers has the potential to achieve the same policy objective more efficiently and

1 with less disruption. These profiles currently do not exist, because there is no rate class
2 for net metered customers. However, if these profiles were created and used to calculate
3 suppliers' load, it would result in a wholesale load obligation for each supplier that more
4 accurately accounts for the load reduction resulting from behind-the-meter generation of
5 net metered customer-generators served by each supplier than the existing load profiles
6 currently provide.

7
8 If the Commission were to see merit in this approach, with the necessary Commission
9 authorization for the Joint Utilities to acquire and install interval meters with a sufficient
10 number of each utility's net metered customers (for those that do not have interval meters
11 already), gather and validate the utility-specific data, and develop the profiles, this is an
12 approach which the Joint Utilities already have the expertise to execute. However, we
13 must provide the caveat that each utility would have to acquire interval meters capable of
14 netting that are also compatible with existing utility billing and meter systems. Though
15 this approach would take incremental resources and a couple of years to execute—hence
16 the need for Commission authorization—it is in our view a more equitable solution as it
17 is less cost, impacts fewer people that would not benefit from the changes, and would not
18 insert risk into enterprise systems of the Joint Utilities.

1 **V. HOURLY NETTING AND COMPREHENSIVE NET METERING STUDY,**
2 **ANALYSIS AND PROPOSAL**

3 **Q. The Office of the Consumer Advocate has proposed that utilities provide hourly**
4 **netting as opposed to monthly netting. Can you explain the logistical implications of**
5 **this shift and the practical impacts of its application?**

6 A. Each of the Joint Utilities has different capabilities when it comes to both metering and
7 billing. But at its core, it seems that shifting to hourly netting from monthly netting
8 would incur substantial complexity in administration, as reflected in each of Eversource's
9 and Liberty's responses to CENH's data request 3-001², included as Attachment B to this
10 testimony, and the corresponding costs of added administrative complexity. And while
11 there is validity in Mr. Woolf's testimony that moving to hourly netting has the potential
12 to result in more accurate compensation for net metering customers, the benefit
13 seemingly would be limited to net metering that incorporated time of use pricing, which
14 is a discussion that OCA itself has deferred to years into the future. But, to make such a
15 change now, absent such a rate structure, makes it unclear what, if any, associated
16 benefits there would be to customers, putting aside the question of whether such benefits
17 would be proportionate to the costs required to implement the change and administer
18 accordingly. So while we see the potential merit in the policy objective of Mr. Woolf's
19 proposal, ultimately we think it is not likely to yield a net benefit to the existing net
20 metering compensation structure and process.

21

² At the time of this filing, Unitil is still finalizing this information.

1 **Q. Can you also comment on Mr. Woolf’s proposal that the Joint Utilities execute an**
2 **analysis of possible changes to the current net metering tariff to be completed by**
3 **December 2025, and the recommendation that the Commission review net metering**
4 **compensation and alternatives to it every three years?**

5 A. Yes. The Joint Utilities are capable of conducting such an analysis, but we question
6 whether the Joint Utilities, rather than the New Hampshire Department of Energy
7 (“DOE”), as the State’s energy policy agency, are the appropriate entities to conduct such
8 an analysis. Ultimately, the Joint Utilities are program administrators, and as such
9 relatively neutral as to the compensation level to net metering customers. We can
10 certainly provide input regarding practical and policy implications of various aspects of
11 such an analysis, the analysis itself – what should be examined and what, if any, changes
12 should be recommended – is a matter of State policy and as such seems to rightfully
13 belong with the DOE. The Joint Utilities would certainly be willing to lend support and
14 expertise where needed and useful.

15
16 We would caution against a three-year Commission review of alternatives to existing net
17 metering. Doing so would not only significantly increase the overall administrative
18 efforts of net metering regulation and administration, it would also inject an element of
19 market uncertainty that could have an unintended detrimental effect on the market.

20
21
22

1 **VI. APPLICATION FEE PROPOSAL**

2 **Q. The DOE in its testimony noted that further detail and a sufficiently granular**
3 **proposal was needed to consider implementing interconnection application fees as a**
4 **part of this docket. Do you have a proposal for consideration of the parties?**

5 A. Yes, we do. The DOE's chief concern was that the Joint Utilities demonstrate that the
6 fees proposed were going to cover only those costs that are incremental and not covered
7 by existing base distribution rates, to avoid "double recovery" of application processing
8 costs; they also wanted a more clearly articulated and definitive proposal, and a
9 description of the benefits that customers will yield in return for these fees. We have
10 addressed both with the proposal included with this testimony as Attachment C, which
11 proposes graduated application fees that begin at \$200 for projects less than 30 kW,
12 increases to \$500 for projects up to 100 kW and \$1,000 for all other applications. The
13 total amount collected through proposed fees will depend on the volume of applications
14 submitted to each utility, but is expected to be generally consistent with the amount of
15 administrative cost each Company anticipates to incur to support the interconnection and
16 enrollment process for customer-generators. These costs that are expected to be funded
17 through fees from customer-generators are presented and described in Attachment C.
18 The administrative costs presented in Attachment C include costs incurred during the test
19 year applied in each company's most recent base rate proceeding that could be
20 reasonably identified to have been incurred directly in support of the interconnection and
21 enrollment process for customer-generators. It is not possible for the utilities to
22 comprehensively isolate all costs historically incurred to support customer-generators

1 since a number of activities are performed in the normal course of business by staff with
2 other responsibilities. For example, the billing department tasks outlined in the Joint
3 Utilities initial testimony are more involved for customer-generators, but have not been
4 managed or tracked separately from other billing operations in a way that would enable
5 the utilities to readily isolate the billing costs that have resulted from growth in the
6 volume of customer-generators.

7
8 The Joint Utility fee proposal includes several provisions that will ensure that the
9 revenues collected by each utility through both fees and base distribution rates are
10 commensurate with the administrative costs incurred to support customer-generators, and
11 that double-recovery of costs does not occur. The Joint Utilities propose to track and
12 report, on an annual basis, (1) the total amount of application fees collected from
13 customer-generators, and (2) the total administrative cost incurred to directly support the
14 interconnection and enrollment of customer-generators. The total amount of application
15 fees will be added to the annual amount of administrative costs incurred during the test
16 year applied in each company's most recent base rate proceeding to determine the
17 revenue each utility received in support of the interconnection and enrollment of
18 customer-generators. If this combined revenue exceeds reported administrative costs for
19 any annual period, the excess revenue shall be credited to all customers through each
20 utilities Stranded Cost Recovery Charge.³ At this time the Joint Utilities do not propose

³ At this time, Unitil intends to credit 100% of application fee revenues to its SCRC deeming its current costs as not incremental. To the extent Unitil hires new employees or temporary help in the future to directly support interconnection and tariff enrollment of customer-generators, these costs would be identified in its annual report and netted from the application fee revenue. In addition, should Unitil incur other incremental costs including but not

1 that any administrative costs in excess of revenue would be eligible for recovery through
2 the SCRC. Utility costs eligible for inclusion in amounts funded by application fees
3 through this proposed mechanism shall also be limited to operation and maintenance
4 costs that can be demonstrated to have been incurred to directly support interconnection
5 and tariff enrollment of customer-generators. Lastly, reported administrative costs shall
6 be subject to review and approval by the Commission in each utility's annual SCRC
7 proceeding.

8
9 **Q. What are the anticipated benefits from implementation of the proposed application**
10 **fee structure?**

11 A. The Joint Utilities believe there are several benefits to implementing the fee proposal. As
12 an initial matter, the proposal will result in a more equitable allocation of utility costs
13 among customer-generators and all other customers in a uniform statewide manner.
14 Services to customer-generators are presently funded through distribution rates paid by
15 all customers. Operation of the fee proposal will ensure that customer-generators fund,
16 through fees, expansion of utility resources that support their interconnection and
17 enrollment.

18
19 The Joint Utilities also expect that the collection of application fees will expand
20 opportunities to improve service to customer-generators. Application fees will
21 automatically support revenue that is directly correlated to the volume of customer-

limited to system or software costs, such as licensing and maintenance fees, those incremental costs would also be applied as an offset to application fee revenues.

1 generator applications and enable the Joint Utilities to responsively expand resources to
2 match customer demand. A dedicated revenue source enables more responsive
3 management of resources than what regulatory and enterprise budgeting processes are
4 likely to support.

5
6 With scalable resources, the application process and processing times are expected to
7 improve or be consistently sustained at a higher level than they otherwise would. While
8 there are too many variables, both on the utility and customer/developer sides of the
9 application process, to offer guarantees or a set number of days for process completion
10 the Joint Utilities are confident that customers will see benefits of these fees. The Joint
11 Utilities propose to provide quarterly reports that includes application processing metrics
12 and narrative descriptions of how each Utility is managing interconnection processes to
13 streamline and expedite the experience of customer-generators. Proposed reports will be
14 sufficiently detailed to assess whether the fees are having the intended effect and support
15 opportunities for the DOE, Joint Utilities and stakeholders to meet and discuss process
16 improvements or adjustments to the fees.

17
18 **VII. CONCLUSION**

19 **Q. Are there any overarching considerations you would like to note?**

20 A. Yes, overall, the Joint Utilities see the merit in fostering the continued growth of DG and
21 the DG market in New Hampshire, as increased implementation of DG advances multiple
22 state policy objectives. The range of proposals contained in the testimony submitted by

1 certain parties to this docket were thoughtfully developed and all aim to fulfill various
2 policy objectives. As administrators of the State's net metering program and tariff, the
3 Joint Utilities have tried to provide additional information and considerations pertaining
4 to some of the recommendations made by those parties so that all parties to the docket
5 and the Commission can proceed with more complete information in reaching
6 conclusions regarding possible changes to the net metering tariff and net metering
7 compensation and the policy objectives represented by New Hampshire net metering.
8 Generally, we are also supportive of any entity supplying energy to customers, whether a
9 CPA or competitive supplier, be able to offer net metering credits, if it can be
10 accomplished in a way that is equitable for all customers and is not disruptive to utility
11 operations. Regarding the current net metering tariff, we still believe that maintaining the
12 status quo of net metering customer compensation levels and process is in the public
13 interest, but also see room for implementing changes along the lines of some of those
14 suggested to foster policy advancement, again taking into account customer equity and
15 feasibility of administration.

16

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

18 A, Yes, it does.