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

TESTIMONY OF

R. Thomas Beach
on behalf of
Clean Energy New Hampshire

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

Docket No. DE 22-060

December 6, 2023

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I. INTRODUCTION

Q: Please state your name, business address and position.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae*, which is **Attachment RTB-1** to this testimony. As reflected in my CV, I have more than 40 years of experience on rate design and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the California Public Utilities Commission (CPUC), working on the implementation of the Public Utilities Regulatory Policies Act of 1978 (PURPA). I also served as a technical advisor to three commissioners from 1984 – 1989. Since leaving the CPUC in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony, studies, or reports on numerous occasions before state regulatory commissions in 20 states, including New Hampshire. My CV includes a list of the formal testimony that I have sponsored before this Commission and in other state regulatory proceedings concerning electric and natural gas utilities.

Q: Please describe your experience on avoided costs, issues related to net energy metering (NEM), and the cost-effectiveness of renewable distributed generation (DG) and other types of distributed energy resources (DERs).

A: I have worked on issues concerning the calculation of avoided cost prices throughout my career, including sponsoring testimony on avoided cost issues in state regulatory proceedings in California, Idaho, Oregon, Montana, Nevada, North Carolina, and Vermont. With respect to benefit-cost issues concerning renewable DG, I have sponsored testimony on NEM and solar economics in New Hampshire and ten other states. Since 2013 I have co-authored benefit-cost studies of NEM or solar DG in New Hampshire as well as Arkansas, Arizona, California, Colorado, North Carolina, South Carolina, South Dakota, and Wyoming. I also co-authored the chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013.[1] Finally, since 2007, I have sponsored testimony on rate design issues concerning solar DG in general rate case proceedings in Arizona, California, Massachusetts, and Texas.

Q: Please specify your prior testimony on NEM issues before this Commission.

A: I submitted direct and rebuttal testimony in Docket No. DE 16-576, the Commission's last major NEM proceeding, on behalf of the Alliance for Solar Choice (TASC). I also was a co-sponsor of supplemental testimony for TASC and other parties concerning the settlement reached in that docket.

Q: On whose behalf are you testifying today?

[1] This report was designed to provide policymakers with tools (including rate design changes) to address key questions concerning distributed generation resources. It has been published in *The Electricity Journal*, Volume 26, Issue 8 (October 2013). It is also available at http://americaspowerplan.com/.

A: I am testifying on behalf of Clean Energy New Hampshire (CENH). CENH's mission is to lead New Hampshire's transition to a zero carbon economy, through renewable energy, energy efficiency and beneficial electrification.

Q: What is the purpose of your testimony in this case?

A: CENH has asked me to review the *New Hampshire Value of Distributed Energy Resources: Final Report* prepared for the New Hampshire Department of Energy by Dunsky Energy + Climate Advisors (Dunsky Report).[2] The Dunsky Report develops a model of the benefits of DERs in New Hampshire, and calculates the future rate and bill impacts of expected DER deployment in the state.

CENH is also sponsoring the direct testimony of Mr. David Littell on DER/NEM policy issues.

Q: How is your testimony organized?

A: The first section reviews the Dunsky Report's avoided cost model of the benefits of DERs. The second section modifies Dunsky's analysis of the future rate and bill impacts of expected DER deployment. The final section recommends policy changes for NEM in New Hampshire, based on the modifications that I have made to the Dunsky Report's modeling.

II. REVIEW OF DUNSKY'S MODEL OF THE BENEFITS OF DERS IN NEW HAMPSHIRE

Q: What is your overall evaluation of the Dunsky Report's avoided cost model of the benefits of DERs in New Hampshire?

A: In general, Dunsky has prepared a reasonable, credible, and comprehensive model of the benefits of DERs in New Hampshire. It is particularly important that Dunsky has modeled a comprehensive set of benefits and has forecasted those benefits over a long-term period that captures most of the expected economic life of the most common DERs

[2] The Dunsky Report is Appendix 1 to the testimony of CENH witness Mr. David Littell. Appendix 2 to Mr. Littell's testimony is the appendices to the Report.

that customers install – solar and small hydro. Dunsky also appropriately updated its work in June 2023 to reflect the higher level of avoided costs in New England in the wake of the Covid-19 pandemic, the war in Ukraine, and emerging infrastructure and supply chain constraints.[3] Finally, the Dunsky Report appropriately considers several sensitivity cases, including a high load growth case to estimate the higher avoided costs that will result if the electrification of buildings and transportation increase future electric demand.

Based on my review, I would make small but important revisions to just two of the avoided cost components of the Dunsky model – avoided line losses and avoided distribution costs. I discuss those modifications next.

A. Marginal Line Losses

Q: What is your concern with the avoided line losses that Dunsky used?

A: The line losses avoided by DERs should be evaluated on the basis of the utilities' marginal line losses, not their average losses. The goal of an avoided cost model is to calculate the costs that the utility would incur but for the presence of a kWh of energy or a kW of capacity supplied by a customer who adopts a DER technology. All of the other major components of the Dunsky model – the locational marginal price for energy, the use of the market-clearing price for generation capacity, and the calculation of marginal or avoided T&D costs – appropriately use marginal values that reflect the change in utility costs when a customer provides its own generation. Avoided line losses also should reflect marginal losses – that is, the change in losses due to a kWh of energy or a kW of capacity supplied by a DER. The issue with the Dunsky model is that it uses marginal losses only for the top 100 load hours and average losses for all other hours;[4] it should have used marginal losses in all hours.

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[3] See *New Hampshire Value of Distributed Energy Resources: Addendum*, filed June 8, 2023. This addendum is Appendix 3 to Mr. Littell's testimony.

[4] See Dunsky Report, Appendix C.9.3 (footnote 20) and C.10.3 (footnote 22): "Apply sector-specific marginal line loss factors to the top 100 NH system peak hours in a year, and sector-specific average line loss factors to the remaining hours."

Q: How does Dunsky calculate marginal losses?

A: Dunsky assumes that marginal losses are 1.5 times average losses, citing a study from the Regulatory Assistance Project (RAP) on the avoided/marginal losses associated with another type of DER – energy efficiency.[5]

Q: Do you agree with the use of this rule of thumb for the relationship between marginal and average losses?

A: Yes. From Ohm's Law one can derive the fact that the marginal line losses in an electric circuit are double the average losses.[6] In practice, if a portion (typically about 25%) of the overall losses on a utility system are "no-load" losses associated with energizing the system, then the marginal losses equal 1.5 times average losses (i.e. 1.5 = 2 x [1 - 25%]), where average losses include both the resistive and no-load losses.[7] Here is a graphic comparison of average and marginal line losses from the RAP Line Loss Study cited by Dunsky, for a hypothetical utility with an average annual resistive loss of 7% on its system, and 25% no-load losses. Note that marginal line losses are as high as 20% in the system peak hour, and marginal losses are about 1.5 times average losses <u>in every hour</u>, not just in the top 100 hours.[8]

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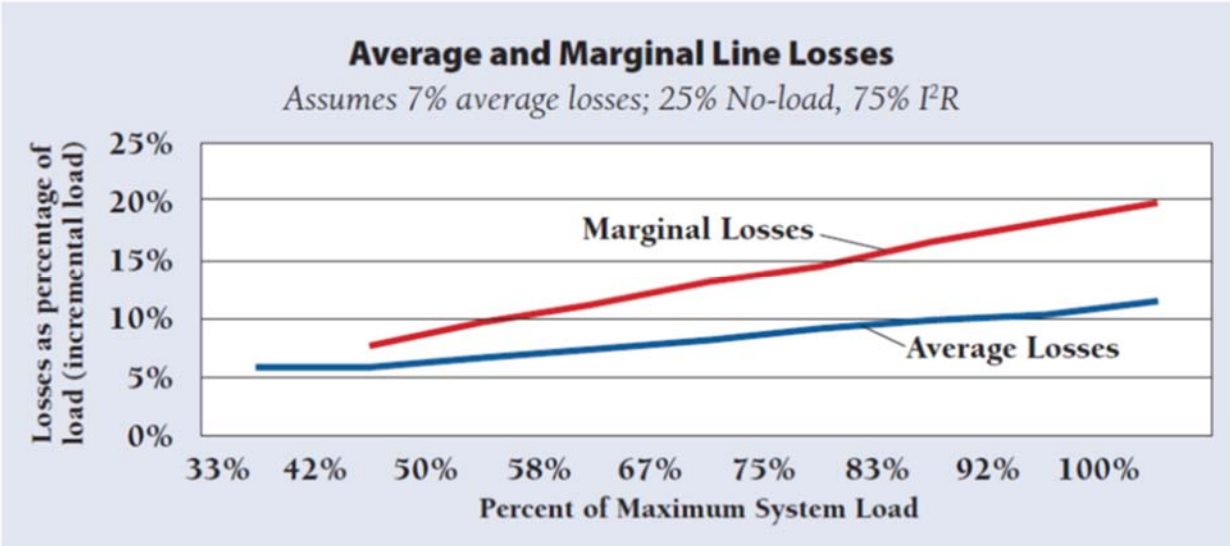
[5] See Lazar and Baldwin, Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), hereafter "RAP Line Loss Study."

[6] See **Attachment RTB-2** for this derivation. This is widely cited in the literature on the treatment of line losses in utility systems. See RAP Line Loss Study, at page 5: "Mathematically, the formula I^2R reduces the marginal resistive loses to a calculation. At any point on the load duration curve, marginal resistive loses are two-times the average resistive losses at that same point on the load duration curve." See https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

Also, Brent Eldridge, Richard P. O'Neill, and Anya Castillo, *Marginal Loss Calculations for the DCOPF, FERC Technical Report on Loss Estimation* (January 24, 2017), at p. 3: "Since losses are approximately quadratic, marginal losses are about twice the average losses."

[7] See RAP Line Loss Study, at p. 5.

[8] *Id.*, at p. 4 (Figure 3).



Assuming that marginal losses are 1.5 times the system average losses across all hours is a conservative (i.e. low) assumption for a DER such as solar, because much of the solar output occurs in the afternoon hours when system loads, and losses, are higher than average.[9] This is an acceptable approximation given that avoided line losses are a relatively small component of the avoided cost value stack.

B. Avoided Distribution Capacity Costs

Q: What are your concerns with the avoided distribution capacity costs used in the Dunsky Report?

A: First, the Dunsky Report is not clear on the nature of the distribution investment data used for this avoided cost component. The report itself says that it calculated the "system-wide avoided cost only," and did not use the locational data on load-related distribution upgrades developed in the Locational Value of Distributed Generation (LVDG) study completed by Guidehouse in 2020.[10] Appendix C.7.3 to the Dunsky

[9] *Id*: "incremental losses during the critical peak period are much larger than the average losses over the year."

[10] Dunsky Report, at p. 10: "Because the capacity-related deficiencies and the related potential avoided costs, reviewed in the LVDG study are highly locational, those costs are not considered in this study, which reviews system-wide avoided costs only." The LVDG study is included as Appendix 4 to Mr. Littell's testimony.

Report states that the report "[a]ssess[es] actual and planned distribution-related capital expenditures, by utility, to determine which expenditures are load-related." The report provides no indication of how Dunsky ascertained which future distribution capital expenditures were load-related. In discovery, CENH asked the utilities for the distribution investment data that they provided to Dunsky, but did not receive consistent or well-documented data.[11] Generally, it appears that it was the utilities that decided which of their distribution investments were "load-related."[12] Further, despite the statement in the report that these avoided distribution capacity costs were calculated "by utility," the Dunsky Report uses the same avoided distribution capacity cost for all three utilities.

Q: What is your concern with having the utilities segregate out those upgrades that are "load-related"?

A: The problem is that there are no clear standards for this "bottom-up" exercise of categorizing specific distribution investments as "load-related," as distinct from other possible categories such as "reliability-related" or "asset-life-related" or "policy-related" (to state policy goals such as interconnecting renewables to achieve RPS requirements). Load growth is often an indirect or secondary factor in many types of distribution expansions and upgrades. For example, an upgrade may be required for reliability reasons to address contingencies that arise under high-load conditions, or to access new generation resources needed to serve growing peak demands. Even asset replacement projects are demand-related in that they are necessary to keep the grid's capacity from declining, and the replacement facilities may have more capacity than the old equipment. Although peak demand may not be the primary driver of any of these types of upgrades, it may be a secondary driver, and demand has a significant overall influence on the need to invest in grid infrastructure in general. The grid is an integrated network, and thus all

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[11] Liberty provided a list of future capacity-related distribution upgrades, but no costs. Unitil's response appears to indicate that it only provided LVDG data to Dunsky, with one minor exception.

[12] For example, Eversource provided Dunsky with its annual investments in "peak load/capacity" distribution upgrades from 2016-2022. These are far smaller than the distribution plant additions that Eversource expects to make from 2023-2027. See Eversource responses to CENH DR 1-5 (confidential) and 1-7 (public).

types of additions to the networked grid may contribute to serving peak demands. Categorizing only certain investments as "load related" or "capacity-related" is likely to understate how transmission costs change as a function of demand.

Q: How do you address this issue in the calculation of avoided distribution capacity costs?

A: A better approach is to use a "top-down" calculation that looks at the long-term change in the utility's overall distribution investments as a function of load growth. To calculate the utilities' avoided transmission capacity costs, I have used a well-accepted regression method. This approach is used by a number of U.S. utilities to determine their long-run marginal transmission or distribution capacity costs that vary with changes in load.[13] The regression model fits incremental transmission or distribution investment additions to peak load growth over time. The slope of the resulting regression line provides an estimate of the marginal cost of transmission or distribution investments associated with changes in peak demand. This marginal cost can be annualized using a real economic carrying charge. The methodology typically uses 15-20 years of data on transmission or distribution investments and annual peak system loads, as reported in FERC Form 1. A portion of this data can be forecast data – for example, for the next 5 years. However, performing this regression analysis on past investments, using FERC Form 1 data, eliminates the uncertainty of forecast data. The regression separates out the influence of load across all of the utility's transmission or distribution investments.

Q: Have you used this approach to calculate the current marginal distribution costs for the New Hampshire utilities?

A: Yes. The results are shown in the first line of **Table 1** below. This approach includes an adder for distribution O&M costs, based on FERC Form 1 data, to capture the ongoing operating costs for marginal distribution investments. As a result, this calculation also incorporates Dunsky's separate component for avoided distribution operating costs.

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[13] For example, Southern California Edison has used this approach for many years to calculate its marginal distribution costs in California regulatory proceedings. See CPUC Application A. 20-10-012, at Exhibit SCE-02, pp. 27-32.

Q: Dunsky's model allocates marginal distribution costs to the hours of the year based on system loads in the top 100 load hours. Do you agree with this allocation?

A: Dunsky's allocation is a reasonable, simple-to-apply approach that appears to capture most of the hours in which distribution circuits peak. Nonetheless, based on my experience with this issue in prior studies, I recommend a more accurate approach of using available substation load data to capture a more granular allocation that considers when various portions of a utility's distribution system peak. To do this, I developed an allocation based on a set of hourly "peak capacity allocation factors" ("PCAFs") derived from recent hourly data on distribution substation loads for each utility.[14] The PCAFs are based on hourly substation loads that are within 10% of the annual peak load at each substation, using this formula:

$$PCAF_s(h) = \frac{(Load_s(h) - Threshold_s)}{\sum_{k=1}^{8760} Max[0, (Load_s(k) - Threshold_s)]}$$

where:

$PCAF_s(h)$ = peak capacity allocation factor for substation *s* in hour *h*,

$Load_s(h)$ = the load for substation *s* in hour *h*, and

$Threshold_s$ = 90% of the substation *s* annual peak load.

All hours where the substation load is below 90% of the annual peak are excluded from the calculation of hourly PCAFs. The loads above 90% of the annual peak are weighted by how much each hour's load exceeds the threshold of 90% of the annual peak.[15] This gives the greatest weight to the annual peak load hour at each substation. The combined

[14] Eversource, Liberty, and Unitil provided hourly load data from 2022 for 51, 6, and 2 substations, respectively.

[15] This approach has been used in the Avoided Cost Calculator (ACC) model of the benefits of DERs developed by Energy and Environmental Economics (E3), and approved by the CPUC for use in DER-specific proceedings in California. See the documentation for the 2022 ACC (version 1b), at pp. 51-52, 61, and 99-108 (Appendix 14.5), discussing the use of PCAF allocations for avoided transmission and distribution costs, available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm.

hourly profile of PCAFs across all of the utility's substations is used to allocate the utility's marginal distribution capacity costs to each hour.[16] This is the revised set of avoided distribution capacity and O&M costs that I recommend replace the corresponding costs in the Dunsky model.

Figure 1 provides a 12-months-by-24 hours heat map of the PCAF-based distribution of avoided distribution costs for Eversource.

Figure 1: *PCAF-based Allocation of Avoided Distribution Costs for Eversource*

Hr\Mo	1	2	3	4	5	6	7	8	9	10	11	12	Total
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
10	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
11	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
12	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	3%
13	0%	0%	0%	0%	0%	0%	2%	2%	0%	0%	0%	0%	4%
14	0%	0%	0%	0%	0%	0%	3%	5%	0%	0%	0%	0%	8%
15	0%	0%	0%	0%	0%	0%	2%	6%	0%	0%	0%	0%	8%
16	0%	0%	0%	0%	0%	0%	4%	9%	0%	0%	0%	0%	13%
17	0%	0%	0%	0%	0%	0%	4%	7%	0%	0%	0%	0%	12%
18	0%	0%	0%	0%	0%	0%	5%	8%	0%	0%	0%	1%	15%
19	1%	0%	0%	0%	0%	0%	7%	8%	0%	0%	0%	0%	17%
20	0%	0%	0%	0%	0%	0%	4%	4%	0%	0%	0%	0%	10%
21	0%	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%	0%	4%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	6%	0%	0%	0%	0%	2%	34%	52%	0%	1%	0%	4%	100%

The PCAF allocation in Figure 1 should be compared to the similar heat map of Dunsky's allocation using the top 100 hours, which is in Appendix C.7.3. The two allocations are similar, with the bulk of avoided distribution costs allocated to afternoon hours in July and August, with a small allocation to evening loads in December and January. The PCAF allocation is more focused on hours later in summer afternoons and also has a small allocation to early morning hours in January. When the Dunsky allocation is applied to a typical solar profile, one kW (nameplate) of solar avoids about 0.51 kW of distribution capacity. This is the capacity contribution or "load match" of

[16] The PCAF allocations at each individual substation are combined using a weighted average based on the annual peak load at each substation.

solar PV to avoiding distribution capacity. The second line of Table 1 shows that, using the PCAF approach applied to substation load data, the comparable PV load matches for the three utilities are lower for Eversource (0.41) and Unitil (0.38) and somewhat higher for Liberty (0.56).

The last three lines of Table 1 complete the derivation of the average avoided distribution capacity and O&M costs for the three utilities, expressed in $ per MWh of solar output.

Table 1: *Avoided Distribution Capacity Costs (includes Avoided O&M)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Marginal Distribution Costs ($/kW-year)	141.12	109.37	99.55
x Effective PV Load Match using Distribution Substation PCAFs	0.411	0.564	0.382
= Distribution Capacity Cost ($/MWh)	58.00	61.68	38.03
÷ Solar Output (kWh per kW-AC)	1,479	1,479	1,479
= Avoided Distribution Capacity ($/MWh)	**39.21**	**41.71**	**25.71**

Q: Can you please summarize your findings on the avoided costs modeled by Dunsky?

A: Yes. The Dunksy avoided cost model undervalues avoided line losses by using marginal line losses only in the top 100 hours. The model also undervalues the marginal costs of distribution capacity and O&M costs, by assuming that a too-small portion of utility investments in distribution are driven by load. On the other side of the coin, the model's use of the top 100 hours to allocate marginal distribution costs across the hours of the year results in PV load match percentages that are too high for Eversource and Unitil, compared to a more accurate method based on granular substation load data. I will assess the impacts of these recommended changes to the avoided cost model in the next section, in which I discuss Dunsky's Rate and Bill Impact analysis.

III. REVIEW OF DUNSKY'S RATE AND BILL IMPACT ANALYSIS

Q: Please describe Dunsky's rate and bill impact (RBI) analysis.

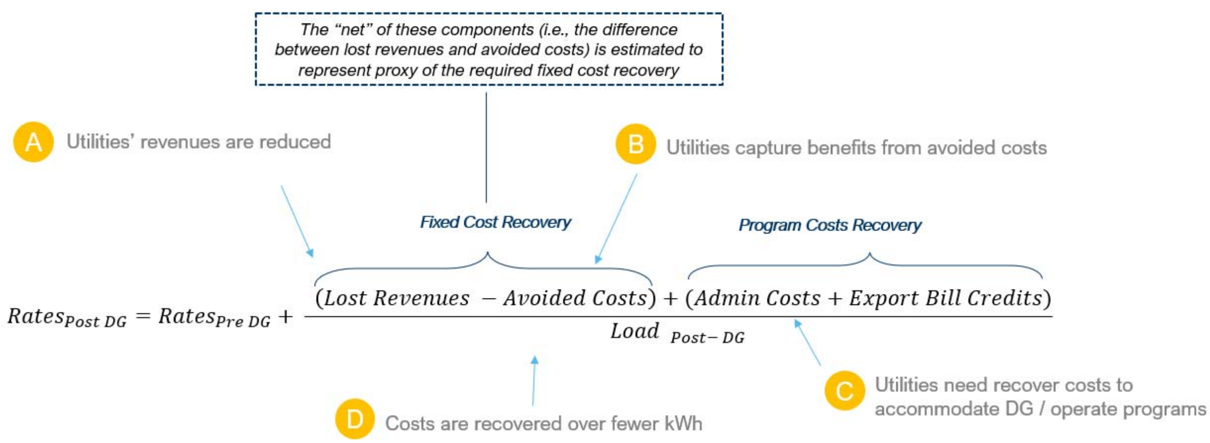
A: Dunsky's RBI assessment is designed to show the impacts on utility ratepayers of future distributed generation (DG) deployment in New Hampshire, considering both the benefits received and the costs incurred by the utilities as a result of incremental DG additions. Dunsky limited its RBI analysis just to solar PV systems. Dunsky shows the rate and bill impacts of forecasted solar deployment on all ratepayers, on non-participating customers, and on DG customers who adopt solar. Dunsky reports these impacts as the average change in customers' rates and bills over the 15-year period from 2021-2035 as a result of solar DG deployment, compared to a case in which none of this new DG is deployed.

Q: Did Dunsky provide a version of their RBI analysis that uses their updated avoided costs in the June 2023 addendum to their report?

A: No, they did not. I have added those updated avoided costs to Dunsky's RBI analysis.

Q: Do you concur with the conceptual framework that Dunsky used in its RBI analysis?

A: Generally, yes. I agree with the formula that Dunsky uses for the rate impacts of DG solar, as shown in this graphic from Section 2.6.3 of the Report.



Q: Did your review of Dunsky's RBI analysis identify any specific issues of concern with portions of the analysis?

A: Yes. My review turned up a number of inconsistencies and possible problems in the RBI spreadsheet model.

- **Use of a different solar profile than in the Dunsky avoided cost model.** In our judgment, the solar profiles used in Dunsky's avoided cost model are reasonable and align with other standard calculators for solar PV output, such as the National Renewable Energy Lab's PVWATTS calculator. However, the RBI spreadsheet uses a different solar profile that is inconsistent with the solar profiles in the avoided cost model and that appears incorrectly to shift solar output to an earlier time of day. The RBI analysis should use the same solar profiles used in the avoided cost model.

- **Use of incomplete or double-counted avoided costs.** The RBI spreadsheet includes a series of flags to designate which avoided costs should apply to future DG. The RBI model that aligns with the results shown in the Dunsky Report does not appear to credit solar DG for avoided generation capacity or DRIPE costs, and it double-counts the avoided risk premium. Excluding or double-counting these avoided costs in the RBI analysis will not value solar DG correctly.

- **Calculation of lost revenues using incorrect export rates.** The calculation of export credits in the Dunsky RBI spreadsheet uses the full volumetric rate as the export credit, and thus fails to pick up the fact that, under the current NEM structure, monthly net exports are priced at less than full retail rates. For residential and small commercial customers (under 100 kW), the export price includes 100% of the generation and transmission rates, but only 25% of the distribution rate. For large commercial customers (over 100 kW), the export rate is limited to only the generation rate component.

- **Assumption that commercial solar customers can avoid demand charges.** The Dunsky RBI analysis calculates lost revenues assuming that commercial customers who install solar can make meaningful reductions in the demand charges that they pay. However, in practice it is difficult for commercial solar customers to reduce their demand charges.

  Dunsky models this reduction in demand charges based on solar's contribution to reducing the coincident peak demands of the New Hampshire utilities. However, this significantly overstates the likely demand charge cost reduction that solar customers can achieve. For some customers, there may be no reduction in demand charges. Commercial demand charges are typically calculated based on the customer's maximum load (in kW) at any time during the monthly billing period, with loads calculated over 15-minute or 30-minute intervals.[17] For example, the coincident peak day in a summer month is likely to be a hot, relatively sunny day with significant solar output. The commercial solar customer's system output is likely to be high on that day, and thus the customer's maximum demand (in kW) on that day may be low. So that peak day is unlikely to be the day which sets the customer's maximum demand for the month, for which the customer is billed a demand charge. The commercial solar customer is most likely to set its maximum demand for the month on a cloudy day when the output of its solar system is low. As a result, the commercial solar customer may achieve little or no demand charge savings.

The essential problem with monthly demand charges is that the solar customer actually may avoid significant demand-related costs – for example, the solar customer's low demand on the coincident peak day may avoid significant generation capacity and transmission costs. However, those savings will not be recognized if the customer pays for those costs in a much higher demand charge for the month based on its higher demand on a cloudy day (when system demands are low).[18]

Commercial rates also can have demand charge "ratchets" based on prior months' loads that bill the customer for a percentage of their highest load over a recent historical period, if that exceeds the current month's maximum load.[19] Demand ratchets essentially impose a floor on the demand reductions that a customer can achieve.

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17 Eversource, for example, uses the maximum demand averaged over a 30-minute period to assess demand charges in its Rate G and Rate LG commercial schedules.

18 This issue has been demonstrated and addressed, for example, in California, where the CPUC approved a series of commercial rate designs for the three major California investor-owned utilities with reduced demand charges (replaced with higher volumetric time-of-use rates) that are available to commercial customers who install solar DG. See CPUC Application A. 12-12-003, *Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association*, served May 10, 2013. Also see CPUC Decision No. 14-12-080, adopting "Option R" rates with reduced demand charges for Pacific Gas & Electric's commercial solar customers, at p. 20:

> "We are persuaded by SEIA's arguments that the current demand charge structure unfairly charges solar customers more for coincident demand related capacity costs than they actually cause PG&E to incur. SEIA's analysis clearly demonstrates that for the five customers chosen by PG&E for its analysis, individual customers' maximum peak period demands did not coincide with the monthly summer peak demands on PG&E's system. Moreover, the average peak period loads were significantly lower than the highest loads for which these customers were billed."

19 For example, Eversource's LG rate has such a demand ratchet that effectively imposes a minimum demand charge each month linked to a percentage of the customer's maximum demand over the prior 11 months.

- **9.54% factor applied to both avoided transmission costs and transmission lost revenues.** The Dunsky RBI model applies this factor to both the avoided transmission costs and transmission lost revenues, dramatically reducing both. Dunsky says that "the rate impacts assessment assumes only the portion [of transmission costs] attributable to the New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%."[20] But New Hampshire ratepayers pay in their rates for 100% of the New England transmission costs allocated to them, and they can avoid 100% of New England ISO transmission charges allocated to the New Hampshire utilities if they reduce their demand during the hours when transmission costs are assessed. This is what is correctly assumed in Dunsky's avoided cost model, but not in its RBI analysis. This 9.54% factor should be eliminated.

In addition, the Dunsky RBI model predates the joint testimony of the utilities proposing, in concept, application fees for new NEM participants. The utilities then supplemented their testimony in discovery, providing a straw proposal for such fees. As discussed in Mr. Littell's testimony, CENH does not oppose the implementation of reasonable application fees, provided the utilities also commit to providing timely service in interconnecting DG customers. An application fee would provide a revenue stream to offset some of the program administration costs included in the Dunsky RBI analysis.

Q: Have you re-calculated Dunsky's RBI results based on all of the issues you have identified in your testimony?

A: Yes. My revised RBI results use (1) Dunsky's updated avoided costs, (2) modifications to address the inconsistencies and problems in the RBI analysis noted above, and (3) revenues from an application fee (based on the utilities' straw proposal), then add (4) marginal line losses in all hours, and finally incorporate (5) the revised avoided distribution costs presented in Table 1 above (with a PCAF-based allocation across hours). **Table 2** shows the cumulative impacts of each of these changes, in terms of the average bill impacts on non-participating Eversource ratepayers over the years 2021-2035, when these changes are made, step by step, to the Dunsky RBI analysis.

Several points about Table 2 need to be emphasized, so that what the table shows is clear. First, the bill impacts shown in the table represent the average change in

[20] See Dunsky Report, at Appendix F.2.2.

customers' bills over all 15 years (2021-2035), compared to a No DG case in which incremental solar DG is not deployed. Second, the starting points for showing the impacts of these changes are the bill impacts on non-participating Eversource ratepayers shown in Figure 30 of the Dunsky Report.[21] These are shown in the first line of the table. Table 2 then makes the successive changes to the RBI analysis shown in the subsequent lines; each line shows the cumulative impact of the change listed in that line plus all of the changes in the preceding lines. Thus, the impacts shown in the bottom line ["Changes to avoided costs"] of the table include all of the changes we made to the RBI analysis. The bottom-line result of these changes is a small reduction of 1% to 2% in the rate and bill impacts for non-participating Eversource customers, compared to Dunsky's RBI analysis.

Table 2: *Impact of Changes to RBI Analysis – Non-participating Eversource Customers*
NOTE: Results in each row include the impacts of all changes made in the prior rows.

Issues		**2021 – 2035 Bill Impact (%)**		
		Residential	SG	LG
Start:	Start: Dunsky RBI analysis – Figure 30	+ 1.03%	+ 0.46%	+ 0.84%
Changes:	Updated avoided costs	+ 0.80%	+ 0.33%	+ 0.68%
[Results in each row include all prior changes.]	Solar profile from avoided cost model	+ 0.44%	+ 0.11%	+ 0.45%
	Use complete avoided costs	+ 0.07%	- 0.10%	+ 0.17%
	Corrected export rates	- 0.05%	- 0.13%	+ 0.17%
	No avoided demand charges	n/a	- 0.31%	- 0.37%
	Remove 9.54% factor on Transmission	-0.27%	- 0.56%	- 0.88%
	Add application fee revenues	- 0.29%	- 0.57%	- 0.88%
	Changes to avoided costs: • Marginal line losses in all hours • Avoided distribution costs (Table 1)	- 0.51%	- 0.70%	- 1.05%

[21] The bill impacts on non-participating Eversource Large General (LG) customers shown in Figure 36 is + 0.5%. The version of the Dunsky RBI analysis that CENH received in discovery showed a bill impact on LG customers of + 0.8%. This difference is unexplained. We have used the higher LG bill impact as the starting point in Table 2.

I have performed analyses similar to the one shown in Table 2 for Liberty and Unitil. The bottom-line results for all three utilities are presented in Table 3, showing the bill impacts after making all changes to the RBI analysis discussed in my testimony.

Table 3: *Impact of Changes to RBI Analysis – Non-participating Customers*

Utility	2021 – 2035 Bill Impact (%)		
	Residential	SG	LG
Eversource	- 0.51%	- 0.70%	- 1.05%
Liberty	+ 0.30%	- 0.15%	- 1.07%
Unitil	+ 0.19%	- 0.14%	- 0.08%
Average	**- 0.4%**	**- 0.6%**	**- 0.9%**

Note: **Table 3** includes all **Table 2** changes for each utility. Average results are weighted by each utility's sales.

Table 3 shows that, when all of these changes are made, the result is that future DER deployment in New Hampshire will result in small decreases in the rates and bills for all non-participating commercial ratepayers and for Eversource's non-participating residential customers. There would be slight rate and bill increases for the non-participating residential customers of Liberty and Unitil. On average statewide, across all three utilities, net metered DG installations will provide a small net benefit to customers, including to customers who do not install solar. Although the changes that I have made to the Dunsky RBI analysis have small impacts, they do reverse the findings of the Dunsky Report that future DER development would result in slight rate and bill increases for non-participants. My revisions support a conclusion that future DER deployment in New Hampshire will result in slight rate and bill decreases for most non-participants.

IV. IMPACTS OF RECOMMENDED CHANGES TO NET METERING

Q: In light of the results of your analysis, what adjustments could be made to NEM policy in New Hampshire?

A: CENH has asked me to assess whether adjustments to the current design of the export rates paid to solar customers could be made, without burdening non-participating ratepayers, in order to provide a stronger incentive for customers to adopt DERs. I used our revised version of the RBI model to assess the bill impacts on non-participating ratepayers if export rates for all customers – residential and small & large commercial – were set at the full volumetric retail rate for each class, assuming all of the changes modeled in Table 2. Those bill impacts are shown in **Table 4** below, for all three utilities. On average statewide, non-participating ratepayers in all three rate classes would continue to realize small net bill reductions after this change in policy to return to full retail NEM based on all volumetric rate components for each class.

Table 4: *Impact of Full Retail NEM – Non-participating Customers*

Utility	**2021 – 2035 Bill Impact (%)**		
	Residential	SG	LG
Eversource	- 0.27%	- 0.64%	- 1.04%
Liberty	+ 0.53%	+ 0.08%	- 1.05%
Unitil	+ 0.40%	- 0.10%	- 0.08%
Average	**- 0.1%**	**- 0.5%**	**- 0.9%**

Note: **Table 4** includes all of the **Table 2** changes for each utility, plus full retail NEM. Average results are weighted by each utility's sales.

Q: Does Mr. Littell's policy testimony for CENH recommend the use of full volumetric export rates to compensate solar DG customers?

A: No, it does not. Mr. Littell recommends a continuation of monthly netting for residential and small commercial customers, with export rates for residential and small commercial customers set using 100% of generation and transmission rates and 50% of distribution rates. He also recommends that large commercial customers should continue to have their imports and exports netted on an hourly basis, with the export rate set at the sum of [a] 100% of the default generation rate; [b] 50% of the volumetric distribution rate; and [c] a volumetric ($ per kWh) transmission adder of 50% of the avoided transmission costs for a solar profile in each year from 2021-2035 as determined by the Dunsky avoided cost model. This transmission adder averages $0.024 per kWh from 2021-2035.[22] In particular, the transmission adder recognizes that solar customers are likely to avoid

[22] This avoided transmission cost is also in real dollars, so it should be escalated with inflation over time.

transmission costs, but, as discussed above, are unlikely to be able to reduce the transmission-related demand charges that they are billed by utilities such as Eversource.

Q: Have you modeled the rate and bill impacts of Mr. Littell's proposal on non-participating customers?

A: Yes, I have. They are presented in **Table 5**.

Table 5: *Impact of CENH Proposal – Non-participating Customers*

Utility	**2021 – 2035 Bill Change (%)**		
	Residential	SG	LG
Eversource	- 0.43%	- 0.68%	- 1.04%
Liberty	+ 0.38%	- 0.07%	- 1.06%
Unitil	+ 0.26%	- 0.12%	- 0.08%
Average	**- 0.3%**	**- 0.6%**	**- 0.9%**

Note: **Table 5** includes all of the **Table 2** changes for each utility, plus export rates for residential and SG that include 100% of generation and transmission rates and 50% of distribution rates. Export rates for LG customers use 100% of generation rates, 50% of volumetric distribution rates, plus 50% of avoided transmission costs for solar. Average results are weighted by each utility's sales.

Q: Does this complete your direct testimony?

A: Yes, it does.