BEFORE THE
STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET **DE 22-060**

IN THE MATTER OF: Electric Distribution Utilities
Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

REBUTTAL TESTIMONY

OF

Alex Hill and Anirudh Kshemendranath

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Introduction

Alexander James Hill

Q. Mr Hill, Please state your full name?

A. My name is Alexander James Hill.

Anirudh Kshemendranath

Q. Mr. Kshemendranath, please state your full name.

A. My name is Anirudh Kshemendranath.

Purpose

Q. Have you previously provided testimony in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. In this Docket, Mr. R. Thomas Beach provided his Direct Testimony on behalf of Clean Energy New Hampshire concerning the "*Consideration Of Changes To The Current Net Metering Tariff Structure, Including Compensation Of Customer-Generators*". In his testimony, he provided a review of the avoided cost model and the rate and bill impact (RBI) analysis and proposed a number of alternative assumptions or alterations to the approach. Our rebuttal testimony addresses a number of points raised by Mr. R. Thomas Beach.

Q. How is your testimony organized?

In the first section of this rebuttal, we address the two points Mr. R. Thomas Beach raised regarding the avoided line loss and distribution capacity cost calculations. The second section of the rebuttal covers the five alternative assumptions Mr. R. Thomas Beach proposed for the RBI assessment. These include 1) Solar Profiles used in the Value of Distributed Energy Resources Study (VDER or Dunsky Report), 2) Treatment of Avoided Costs, 3) Treatment of

Export Rates, 4) Commercial Solar Demand Charge Savings, and 5) the New Hampshire (NH)-specific factor applied to Both Transmission Costs and Lost Revenues.

Response to Mr. R. Thomas Beach’s Comments on the VDER Components

Avoided Line Losses

Q. Briefly summarize Mr. R. Thomas Beach's proposed approach for calculating avoided line losses.

A. As per the testimony of Mr. R. Thomas Beach, he suggested that the avoided line losses by customer-generator resources should be based on the Electric Distribution Company’s (EDC's) marginal line losses rather than average losses. Mr. Beach endorsed Dunsky's approach to calculating the relationship between marginal and average line losses but suggested that Dunsky should have applied marginal line losses in all hours instead of just the top 100 hours.

Q. What is Dunsky's response to the proposed approach?

A. In the VDER Study, Dunsky applied a conservative approach by assuming that the marginal line losses would apply to the top 100 system load hours when the current flowing through the transmission and distribution system would likely be at its highest. It is possible that Mr. Beach's suggested approach would provide enhanced precision in the avoided line loss calculation. However, upon further analysis, we determined that it would have a negligible effect on the overall technology-neutral value stack.

Q. What is the overall impact of applying marginal line losses to all hours?

A. When Dunsky applied marginal line losses to all hours, the avoided transmission line loss values increased notably. However, the resulting impact on the total value stack averaged across the study period (2021-2035) is less than 1% and is therefore considered to have a negligible impact on the overall study results.

Table 1: Impact of Applying Marginal Line Losses to all hours (assumed to be 1.5 times average line loss)

Technology Configuration	Original Value (Avg 2021-35) $/kWh (a)	New Values (Avg 2021-35) $/kWh (b)	Incremental Increase (%) (b-a)/a	Impact on the Value Stack
Transmission Line Loss	$0.0016	$0.0023	42%	0.38%
Distribution Line Loss	$0.0025	$0.0035	37%	0.55%

As seen in Table 1 above, the original average avoided transmission line losses across the study period (2021-2035) was valued at $0.0016 per kWh, while the original average avoided distribution line losses across the study period (2021-2035) was valued at $0.0025 per kWh. After applying the marginal line losses to all hours, the new average avoided transmission line losses across the study period (2021-2035) increased to $0.0023 per kWh, while the new average avoided distribution line losses across the study period (2021-2035) increased to $0.0035 per kWh. Thus, the avoided transmission line losses averaged across the study period (2021-2035) grew by 42%, and the avoided distribution line losses averaged across the study period (2021-2035) increased by 37%. After considering the impact of marginal line losses for all hours, the total technology-neutral value stack averaged across the study period (2021-2035) increased by approximately 1%.

<u>**Avoided Distribution Capacity Costs**</u>

Q. Briefly summarize Mr. R. Thomas Beach's questions regarding the avoided distribution capacity costs.

A. The Direct Testimony of Mr. Beach mentioned that the Dunsky Report is unclear on the nature of the distribution investment data used for this avoided cost component and that the report did not appear to use the locational data on load-related distribution upgrades developed in the "Locational Value of Distributed Generation (LVDG)" study completed by Guidehouse in 2020 (Page 6, Line 12-16).

Q. What is Dunsky's response to Mr. R. Thomas Beach's question regarding applying LVDG Study results in the VDER Study?

A. Dunsky conducted the VDER Study based on the predetermined scope outlined by stakeholders. As part of our approach, we utilized the values and Real Economic Carrying Charge (RECC) methodology mentioned in the LVDG study to determine the annual avoided distribution capacity costs, expressed as $/kW-yr, in the VDER Study.

Q. How did Dunsky calculate the avoided distribution capacity costs in the VDER Study?

The LVDG Study reviewed 696 locations and identified 122 locations on the electric distribution companies (EDC) distribution systems (i.e., circuits and substations) with capacity deficiencies, where capital investments potentially could be avoided through load reduction attributable to Net Energy Metering (NEM) eligible Customer-Generators. The LVDG Study then used the load growth forecast scenarios provided by the utilities to identify actual or potential capacity-deficient locations, from which a subset of sixteen substations was selected for detailed analysis.

Dunsky then used the values and methodology in the LVDG Study to develop New Hampshire-specific System-wide Annual Avoided Distribution Capacity Costs ($/kW-yr). The approach is broken down into two steps:

1.) **Estimate the Annual Revenue Requirement ($M per year):** According to the LVDG Study, capacity deficiencies are only triggered in thirteen of the sixteen assessed substations under the base-case load growth forecast. The LVDG Study estimated the total revenue required to upgrade each substation (LVDG Study: Page 42, Table 15). However, the Study did not determine a system-wide value for lower order distribution investment deferral costs. To account for these costs, Dunsky increased the total revenue requirements for each substation by 1% in the VDER Study. The total revenue requirement to upgrade the substations was then calculated for each EDC.

Dunsky then used the Real Economic Carrying Charge (RECC) methodology described in the LVDG Study to annualize the total revenue requirement to arrive at the annual avoided distribution capacity costs ($M per year). Key inputs to the RECC method include the revenue requirement, inflation rate, weighted average cost of capital (WACC) for each EDC, and asset lifetime, assumed to be 30 years for all assets evaluated.

2.) **Estimate the Annual Avoided Distribution Capacity Costs ($/kW-yr):** The LVDG Study provided each EDC's Forward-Looking Location Capacity Deficiencies (MW per year) by year from 2020 to 2029. Dunsky extrapolated these values to 2035 based on a trendline analysis and applied them to calculate the Annual Avoided Distribution Capacity Costs ($/kW-yr) by dividing the Annual Revenue Requirement ($M per year) by the Annual Capacity Deficiency (MW per year). This determined the annual avoided distribution capacity costs ($/kW-yr) specific to each EDC. Finally, the EDC-specific avoided distribution capacity costs were rolled up to calculate the New Hampshire-specific System-wide Avoided Distribution Capacity Costs ($/kW-yr).

Response to Mr. R. Thomas Beach's Comments on the RBI Assessment

Solar Profile

Q. Why is the Solar Profile in the RBI assessment different from the one used in the VDER model?

A. In the VDER workbook, Dunsky averaged the solar profiles from PV Watts by the summer and winter months. This was done to smoothen out the irregularities in the production profile and ensure cleaner charts. In the RBI assessment, actual PV Watts data were used.

Treatment of Avoided Costs in the RBI Assessment

Q. Briefly summarize the conceptual framework for calculating Rate and Bill Impacts used in the Study.

A. The RBI assessment is intended to serve as a future-looking estimate of the direction and magnitude of the impacts of Customer-Generator (CG) deployment on all ratepayers and any potential cost-shifting between customers with and without CG. It is not intended to be a projection of future electricity rates and cost recovery, but it serves as a future-looking approximation of the impacts of future CG adoption on retail electricity rates for New Hampshire customers.

Based on the RBI framework applied, as presented in Figure 1 below, the impact on the pre-CG rates is due to the fixed program costs recovered by the utilities to maintain revenue requirements. The fixed cost recovery portion is estimated to be the difference between the lost revenues and the avoided costs, while the program costs include the administration cost and the export bill credits. The administration costs are the costs that the EDC will incur to accommodate Customer-Generators and operate the programs, while the export bill credit is the credit paid out to the Customer-Generator for their exports to the system.

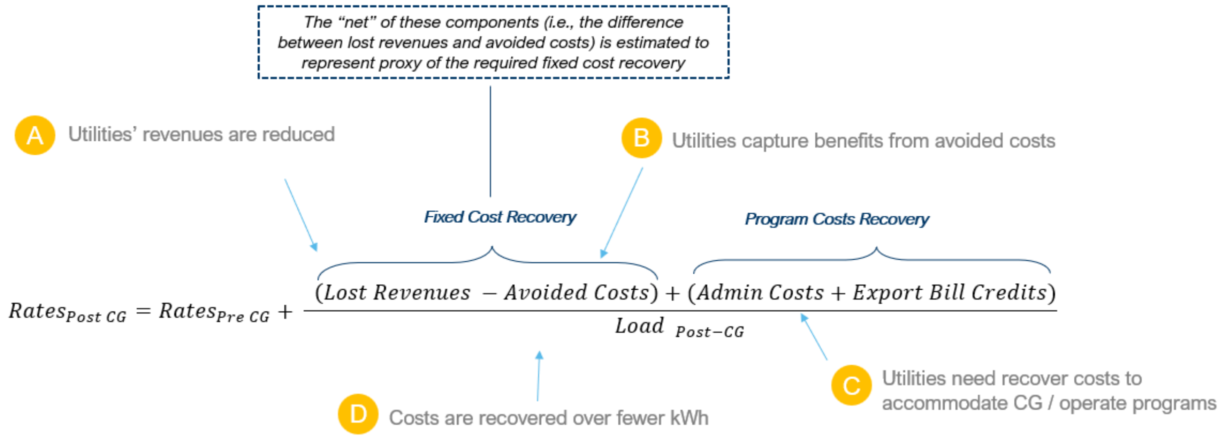

Figure 1: Rate and Bill Impact Framework

The above approach was used to calculate the impacts on the generation, transmission and distribution rates. The program costs are assumed to be recovered only through the distribution rate.

Impact on Generation Rates: We assume that the Generation Rates are impacted by the fixed costs, estimated to be the difference between the lost revenue and the avoided costs. The generation avoided costs include energy, capacity, line losses, risk premium, ancillary, Renewable Portfolio Standard (RPS) compliance benefits and Demand Reduction Induced Price Effects (DRIPE). To estimate the fixed cost impact of adding further Customer Generators to the system in this study, we have used an approach that is consistent with the method previously developed by Synapse Energy Economics Inc. (Synapse) in the "New Hampshire Rate, Bill, and Participation Impact Analysis" study. This helped ensure that our assessment was conducted in line with other RBI evaluations conducted in New Hampshire, per the study RFP requirements. Under this approach, all avoided cost components are treated as a pass-through from the market to the utility customers, with the exception of DRIPE and avoided capacity costs, which is assumed to be embedded in the generation rates[1]. Stated differently, it is assumed that within a reasonably realistic range of Customer Generators adoption, the avoided cost values of all these components are not impacted by the amount of Customer Generators added to the system, with the exception of DRIPE and avoided capacity costs, and thus they only impact customer bills, but not the generation rates. DRIPE is a market effect that results in lower market clearing prices for energy and capacity. This price suppression benefit is ultimately passed on to market participants and their customers through reductions in the generation rate.

For capacity costs, as Customer Generators are added to the system, the utilities reduce the amount of generation that they need to purchase, but not the associated variable charge portion of the generation rates. However, this does lead to reduced capital costs in the future, which should then lead to a reduction in generation rates, as is captured in the model.

In response to Mr. Beaches' comment regarding the perceived double counting of the risk premium avoided costs, we respond that this was not the case. For the reasons outlined above, the risk premium does not factor into the RBI assessment's fixed cost calculation. To be certain, we returned to the RBI model and confirmed that the risk premium does not impact the RBI results.

However, in returning to the RBI model to prepare this response, we did however encounter and correct an error in how the model was applying the DRIPE and avoided capacity costs in the generation rate impact calculation. Stated simply, the model should have subtracted the impact of these factors from future generation rates, but instead added them. We have made

[1] We note that Synapse also included a "Reliability" factor in their analysis, which was not included as a pre-determined part of the VDER value stack, and was subsequently not applied in the RBI assessment.

this correction, and will be issuing an addendum to the RBI chapter of the report to reflect the following changes.

Table 2: Comparison of Rate and Bill Impact results between the VDER Study Report and the updated values after the DRIPE and Capacity Cost treatment correction

Utility	Customer Class	Volumetric Rate Impact*		Non-CG Bill Impact		CG Bill Impact	
		Report	Update	Report	Update	Report	Update
Eversource	Residential	1.21%	0.65%	1.01%	0.55%	-92.3%	-92.3%
	Small General Service	0.58%	0.26%	0.46%	0.31%	-93.6%	-93.6%
	Large General Service	0.66%	0.13%	0.52%	0.51%	-41.5%	-41.6%
Liberty	Residential	1.77%	1.33%	1.51%	1.12%	-90.6%	-90.6%
	Small General Service	1.09%	0.70%	0.97%	0.63%	-93.8%	-93.8%
	Large General Service	1.13%	-0.01%	2.62%	1.69%**	-31.3%	-32.0%
Unitil	Residential	1.85%	1.22%	1.52%	0.99%	-87.4%	-87.4%
	Small General Service	0.26%	0.11%	0.29%	0.17%	-92.3%	-92.3%
	Large General Service	0.20%	0.07%	0.31%	0.20%	-4.23%	-4.34%

**Combined impact of forecasted added Customer Generators on Generation Rates, Transmission Rates, and Distribution Rates*

*** It is noted that despite a minor overall reduction in volumetric rates for Large General Service customers, they experience a slight increase in their bills. This is due to increased demand charges resulting from fixed costs, and program costs spread over a reduced customer class peak demand.*

Overall, as is presented in Table 2, the corrections indicate adding further Customer Generator capacity will 1) reduce generation rates 2) lead to smaller than initially indicated utility rate increase overall, and 3) lead to a somewhat smaller than initially indicated increase in non-Customer Generator bills and a further reduction in Customer-Generator bills. These findings do not change the overall conclusion of the study, but do indicate that adding Customer Generators to the system have an even lower potential to cause bill increases for, or cost-shifting to, non-Customer-Generator than was stated in the report.

Export Rates

Q. How did the RBI Model treat exports under the current NEM structure?

A. We concur with Mr. Beach's statement that under Alternative NEM, the export rate for residential and small commercial customers should be 25% of the distribution rate and 100% of the transmission and generation rates. For large commercial customers, the export rate should be limited to the generation component only. The RBI model applied the appropriate export rate assumptions to calculate generation, distribution and transmission rate impacts.

Commercial Solar Demand Charge Savings

Q. What is Dunsky's Response to the concerns raised by Mr. R. Thomas Beach?

A. In his Testimony, Mr. Beach states that commercial customers who install solar cannot significantly reduce demand charges. Therefore, the RBI analysis should not include demand charge savings for solar customers. While this could be true for some customers, it is expected that the impact of Customer-Generators on customer peak demand charges would vary depending on a range of factors, such as the size of the Customer-Generator system relative to the customer's overall peak demand. A recent study from Lawrence Berkely National Laboratory, titled "Exploring Demand Charge Savings from Commercial Solar" (2017), provides further insight into the range of appropriate assumptions related to potential demand charge savings from solar PV. The study highlights an analysis of a range of building types equipped with a PV system with a PV-to-load ratio of 50%, which results in a median reduction in demand charges of 7%, which translates into an effective coincidence factor or 0.14, as compared to the 0.27 coincidence factor that we assumed for small general customers in the study. Moreover, the LBNL study indicated that "Demand charge savings increase with PV system size, but with diminishing returns", and thus, for systems sized to less than 50% of the peak demand, the impact on demand charges would likely be higher. Thus, while our analysis may have applied a higher-end assumption on the peak demand charge impacts, Mr. Beach's supposition that the demand charge impacts would be near zero likely represents an overly pessimistic perspective on the issue, and the reality would likely fall somewhere in the middle.

Thus, the demand charge savings could be lower in some cases; however, the overall objective of this analysis was to determine the overall magnitude and impact on the rates.

<u>NH Specific Factor Applied to Transmission and Lost Revenues Charges</u>

Q. What is the rationale for applying a 9.54% factor to the transmission lost revenues and avoided costs?

A. Dunsky was instructed in the scope of the VDER Study and RBI assessment to maintain consistency with other energy efficiency studies in New Hampshire. As such, the RBI approach Dunsky adopted is consistent with the "New Hampshire Rate, Bill, and Participation Impact Assessment", which was prepared for the New Hampshire Evaluation, Measurement, and Verification Working Group. ISO New England sets the transmission rates for pool transmission facilities for the entire New England region. That study applies the same 9.54% factor, which is considered a valid assumption.

Each load-serving entity in New England (including each New Hampshire EDC) pays the same rate for pool transmission facilities, and actions taken in one state are experienced by all other states in the region proportional to their relative transmission requirements. Since New Hampshire is a part of the ISO-NE system, all the transmission benefits and costs are shared among the participants of the ISO-NE wholesale market. When Customer-Generators in New Hampshire create an avoided transmission benefit, those benefits are redistributed among all the participating states, and the benefit to New Hampshire is proportional to the state's contribution to the regional transmission demand. This is estimated at 9.54% using the ISO New England's Monthly Regional Network Load Cost Report. Similarly, when Customer-Generators in other states, say Massachusetts, reduce the regional transmission costs, customers in New Hampshire will also see the benefit of reduced transmission costs, again proportional to New Hampshire's contribution to the regional transmission demand. This approach is based on how transmission costs are allocated within ISO-NE. As seen in Figure 2, New Hampshire's contribution to the ISO New England's regional system peak has remained largely stable from 2016 to 2022.

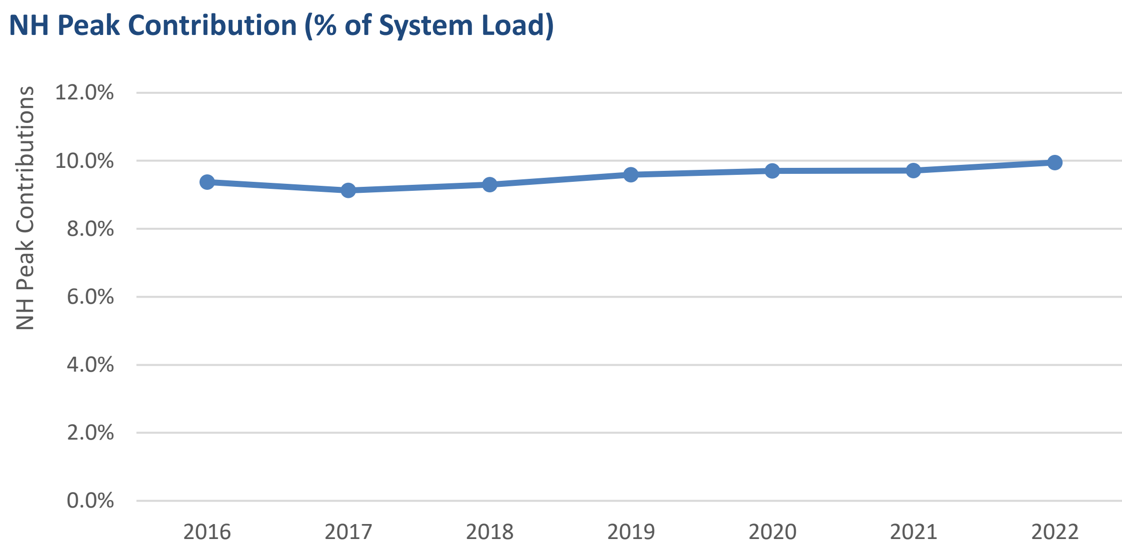

Figure 2: New Hampshire Load Zone Contribution to ISO-NE Regional Peak (ISO-NE Energy, Load, and Demand Reports)

While we recognized that New Hampshire's portion of the pool transmission is reassessed each year, the study scope did not include recalculating this value under varied Customer-Generator adoption rates in each state. Considering that the future portion of the pool transmission attributable to New Hampshire would be impacted by changes across all the ISO-NE market participants, this assumption reflects the likelihood that New Hampshire's portion of the overall transmission needs is not likely to change substantially relative to the other ISO-NE participants over the study period.

Q. Does this conclude your testimony?

A. Yes.