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

DIRECT TESTIMONY

OF

Alex Hill and Anirudh Kshemendranath

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<u>Introduction</u>

<u>Alexander James Hill</u>

Q. Mr Hill, Please state your full name?

A. My name is Alexander James Hill.

Q. By whom are you employed, and what is your business address?

A. I am employed by 6893449 CANADA INC (doing business as Dunsky Energy + Climate Advisors), and my business address is 50 Ste-Catherine St. West, Suite 420 Montreal, QC, H2X 3V4.

Q. Please summarize your education and professional work experience.

A. I have a Bachelor's degree in Chemical Engineering from McGill University in Montreal, Quebec, Canada (Graduated 1996) and a Master's degree in Civil Engineering also from McGill University (Graduated 2000). I joined Dunsky Energy + Climate Advisors (Dunsky) as a Senior Consultant in 2012, and I became a Partner in the company in 2015. At Dunsky, I lead two areas of practice: our Opportunity Assessment practice, which includes our various distributed energy resources modelling and analytics work, as well as our Financing Practice, through which we assist clients in providing strategic analysis, feasibility studies, program designs and program evaluations. Prior to joining Dunsky, I performed various independent renewable energy and energy efficiency consulting contracts over the 2009 to 2012 period. From 2005 to 2010, I was the General Manager of Green Energy Benny Farm in Montreal, Quebec, and in parallel, from 2007 to 2009, I was a Project Manager for Ecocité Development in Montreal, Quebec. From 2000 to 2005, I worked as the Environmental Program Manager at Alternatives Inc. in Montreal, Quebec.

Anirudh Kshemendranath

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

A. My name is Anirudh Kshemendranath.

Q. By whom are you employed, and what is your business address?

A. I am employed by 6893449 CANADA INC (doing business as Dunsky Energy + Climate Advisors), and my business address is 555 Richmond St W #1110, Toronto, ON M5V 3B1.

Q. Please summarize your education and professional work experience.

A. I completed a Bachelor of Technology in Metallurgy and Material Science from the National Institute of Technology, Nagpur, India, in 2013. I also obtained a Master of Science Degree in Energy Science Technology and Policy from Carnegie Mellon University, Pittsburgh, Pennsylvania, USA, completed in 2014. I have obtained a Master of Business Administration (MBA) degree from Quantic School of Business and Technology, licensed by the District of Columbia Higher Education Licensure Commission in Washington, DC, completed in 2021. I have been a Consultant at Dunsky Energy and Climate Advisors since April 2022 and a Senior Principal Analyst since August 2021. At Dunsky, I provide analytical and strategic consultation on energy storage, solar adoption, the value of DERs, utility planning, and rate design. Before that, I worked as an Independent Senior Principal Analyst with Dunsky Energy and Climate Advisors from August 2019 to July 2022. Between November 2018 and March 2019, I worked as a senior consultant at Fractal Energy Storage Consultants based in Austin, Texas. From November 2015 to October 2018, I worked as a Consultant at Strategen Consulting, Inc., a clean energy strategy consulting firm based in Berkeley, California. During that time, I have supported policymakers in creating clean energy roadmaps, helped energy developers evaluate the financial viability of their projects, and advised corporate clients on market entry strategies for new or existing energy products. From February 2015 to October 2015, I worked at Robert Bosch Research and Technology Center North America as Business Development Intern on both the direct current microgrids and the battery and energy storage systems teams.

<u>Purpose</u>

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to provide an overview of the Value of Distributed Energy Resources study and its findings, along with the associated analytical tools.

Q. Did you prepare the Final Report on the New Hampshire Value of Distributed Energy Resources and Appendices (VDER Study) resources filed in this matter on October 31, 2022, at Docket Tab 9?

A. We each played a central role in preparing the VDER study, alongside other colleagues who worked at Dunsky at the time. Mr. Kshemendranath built the VDER analytical tools behind the study, conducted the analysis, and contributed to the quantitative and narrative. Mr. Hill acted as the internal project sponsor (titled Project Director at Dunsky) and, through that role, led the team to develop the report outline and logical structure and conducted a full editorial review of each iteration of the VDER report, providing input and direction to the content.

<u>Focus and Scope of VDER Study</u>

Q. Please describe in brief terms the overall focus of the VDER Study.

A. The VDER study assesses the value of behind-the-meter (BTM) Distributed Energy Resources (DERs) that are owned by customers-generators and are eligible to participate in net energy metering (NEM) programs within the service territories of the regulated distribution utilities in New Hampshire. It provides an assessment of the relative benefits and costs of net-metered distributed generation (DG) from the perspectives of the utility system as a whole, DG customer-generators, and non-DG customers.

Q. Did you perform the VDER Study in accordance with a predetermined scope?

A. Yes.

Q. Where did the predetermined VDER Study scope come from?

A. The scope for the VDER Study was formally established in the New Hampshire Public Utilities Commission (Commission) Order No. 26,316 (December 2019 Order). It was then provided as Appendix A in REQUEST FOR PROPOSALS (RFP) RFP #2020-001 issued by the Commission on March 27, 2020, to which Dunsky submitted a proposal to conduct the VDER Study to meet the predetermined scope.

Q. Please describe in brief terms the scope of the VDER Study.

A. The VDER Study scope prescribes developing net present value avoided cost estimates over a 15-year forward-looking period resulting from NEM-eligible DERs that are interconnected to a New Hampshire-regulated distribution utility. The assessment provides an estimate of the direction and magnitude of net avoided costs as well as the direction and magnitude of rate and bill impacts of DG deployment to identify any potential cost-shifting between DG customer-generators and non-DG customer. It does not propose to represent an exact projection of future electricity rates and utility cost recovery, nor provide proposed exact compensation rates for NEM DG-customer-generators. The scope dictates that the study assesses the relative benefits and costs of NEM DERs from the perspective of the utility system as a whole and utility ratepayers' perspective (both NEM DG customer-generator and non-DG customers). The study was to focus on load reduction values and maintain consistency with standard benefit-cost analysis criteria as applied for energy efficiency resources in the state, applying the Utility Cost Test (UCT) and a customer rate and bill impact analysis.

The VDER Study scope outlines nineteen (19) Avoided Cost criteria to be evaluated through a value-stack approach, as determined through a stakeholder process and approved by the Commission. The scope prescribes that 3-5 years of historical data be applied where possible to validate future projections, along with data from the most recent Avoided Energy Supply Cost (AESC) in New England study and the Locational Value of Distributed Generation study, to formulate inputs as appropriate. The avoided costs also include a number of "hard-to-quantify" criteria proposed to be evaluated through either quantitative proxy values or qualitative review. Net avoided costs were to be presented on a net present value basis using appropriate discount rates.

Certain avoided costs contributing to the VDER are time and/or location dependent. For each avoided cost criterion applied, hourly avoided cost values accounting for time and locational dependencies (where appropriate) were to be developed, thereby enabling a technology-neutral analysis of marginal avoided cost components. After developing a technology neutral avoided cost analysis for hourly load reduction across the study time period, distributed generation (DG) production curves were to be used to determine avoided costs for various DG technologies, specifically solar photovoltaic and hydroelectric as contemplated by Order No. 26,029. The scope also includes sensitivity analyses to determine the demonstrable and quantifiable net benefits associated with relevant externalities, such as environmental benefit, while adequately mitigating the potential for double-counting such externalities. The scope also included development of net DG customer-generator installed costs (including incentives) which could be used in future proceedings to evaluate how NEM compensation rates may impact opportunities to invest in DG in the state and receive fair compensation. The VDER study scope also included a consumer rate and bill impact (RBI) assessment, to determine the effects on utility ratepayers and the potential for cost-shifting between customers participating and those not participating in net metering.

VDER Study Methodology

Q. Please provide a brief overview of the methodology used in conducting the VDER Study.

A. The VDER study methodology framework can be summarized by five high-level steps, outlined below: First, technology-neutral avoided cost values were established (step 1). Next, DER production curves were developed for each resource type (step 2), and the technology-neutral avoided costs were applied to the resulting production curves to calculate the avoided cost value of DERs by system type (step 3). Avoided cost values were also calculated under sensitivity cases, including consideration of environmental externalities, high load growth scenarios, and a market resource value scenario (step 4). In addition to the value stack components, we calculated the net present cost for each system type, considering upfront and operational costs to DG customer-generator as well as available incentives. Because this study focuses on avoided utility system costs, these DG customer-generator costs are not included in base values, however the study scope contemplated that in the future, those estimated costs could be used to assess the cost-effectiveness of DER systems from the perspective of DG customer-generators against alignment with a reasonable compensation rate. Finally, the rate and bill impacts were assessed, determining how DER deployment and compensation will affect New Hampshire rates and customer bills (step 5).

The RBI assessment provides high-level insight into the impact of DG deployment in New Hampshire on ratepayers, considering the benefits received and the costs incurred by the utilities as a result of incremental DG additions (which, for the purpose of this analysis, are limited to solar PV systems), and considering how those values are passed on to ratepayers.

The RBI methodology can be summarized by four high-level steps. As the first step, solar PV system archetypes are defined for each utility (Eversource, Unitil, and Liberty) and for representative rate classes (residential, small commercial, and large commercial). Next, the incremental impacts associated with future DG deployment were evaluated, applying forecasts from the Independent System Operator-New England (ISO-NE), which assumes that 140 MW of additional DG (solar PV) will be deployed in New Hampshire between 2021 and 2030. The future deployment of DG is expected to create both upward pressure on rates (due to lost utility revenues and program cost recovery, and downward pressure on rates (due to avoided utility costs). As the third step, the impact on retail rates was assessed. To illustrate the impacts of different potential DG program designs on ratepayers, changes to rates were assessed under two scenarios for DG compensation:

(1) Alternative NEM Tariff Scenario: Assumes DG exports are compensated at a rate that is in alignment with the current alternative NEM tariff compensation rates in the state

(2) Avoided Cost Value Stack (ACV) Tariff Scenario: Assumes that DG exports are compensated at an avoided cost rate that is in alignment with the calculated value stack assessment.

Finally, the impact on customers' bills was assessed as an indication of the overall impact to customers, and to determine any potential cost-shifting. Changes to bills are assessed under two scenarios: the NEM scenario and the ACV scenario described above. The results are largely focused on presenting the average percent increase/decrease in customers' monthly bills attributable to DG from 2021 to 2035 for each of the typical customer archetypes to indicate the long-term impacts of DG on utility customers.

In keeping with the study goals of maintaining consistency with energy efficiency cost-effectiveness evaluation, avoided cost values from the AESC study (2021 edition) were used wherever possible. For avoided cost criteria that are not included in the AESC study, relevant inputs were gathered through a combination of New Hampshire utility data requests, utility interviews, and literature reviews. In the updated addendum (submitted on 8th June 2023, Tab 43 in DE 22-060), across all criteria, prices were adjusted to real 2024 dollars and $/kWh values were calculated for each hour of the study (8,760 hours per year, years 2024-2035).

Based on data availability, value stack components were evaluated using 1) AESC study, 2) Quantitative methods unrelated to AESC, or 3) Qualitative review. The following cost components were assessed using the AESC data, methods, and results: Avoided Energy, Avoided Capacity, Avoided Ancillary Services and Load Obligation Charges, Avoided RPS Compliance Charges, Avoided Transmission and Distribution Line Losses, Wholesale Market Price Suppression Benefits, Avoided Wholesale Risk Premium and Environmental Externality Benefits. Other value stack components were evaluated using quantitative methods unrelated to AESC; these include Avoided Transmission Charges, Avoided Distribution Capacity Costs, Distribution System Operating Expenses, and Distribution Utility Administration Costs. Due to data limitations, four value components were not quantified; instead, a qualitative review was applied as per the predetermined scope description discussed earlier in this testimony. These include the Avoided Transmission Capacity, Avoided Transmission and Distribution System Upgrades, Distribution Grid Support Services and Resiliency Services, and as a result, they were not captured in the technology-neutral avoided value stack.

Eight distributed energy resources were assessed in this study. These include small hydro, behind-the-meter residential south-facing solar, behind-the-meter residential west-facing solar, behind-the-meter commercial south-facing solar, behind-the-meter commercial west-facing solar, front-of-the-meter solar, behind-the-meter residential south-facing solar coupled with energy storage, and behind-the-meter commercial south-facing solar coupled with energy storage.

Some criteria were not included in the total avoided cost value stack but were assessed to contribute to other aspects of the VDER study. The Environmental Externalities were applied as a sensitivity to the avoided cost value stack; these represent benefits/costs not already included in energy prices and external to utility system valuation and are not currently included in NEM tariff design. The Utility Lost Revenue was assessed as part of the Rate and Bill Impact analysis to determine the potential cost-shifting effects and was not included in the avoided costs stack. Customer Net Installed Costs were assessed to evaluate how NEM compensation may impact opportunities to invest in DG in the state. In the future, it may be used to assess the cost-effectiveness of the DG systems from the perspective of customer generators with net-metered DG systems.

<u>VDER Data and Data Sources</u>

Q. What were the data and sources of the data you analyzed in the VDER Study?

A. The following data and sources were leveraged to conduct the VDER study:

1) From the 2021 Avoided Energy Supply Cost Study, we used the hourly ISO-NE and New Hampshire system load curves, wholesale hourly energy prices, forecasted capacity prices, reserve margin, RPS compliance costs, transmission line losses, price elasticity curves, gross demand reduction induced price effect (DRIPE) energy price forecasts, uncleared capacity DRIPE Forecast, electric-gas-electric (E-G-E) cross DRIPE coefficients, wholesale risk premium, carbon dioxide (CO2) marginal emissions rates, societal cost of carbon, nitrogen oxide (NOx) marginal emissions rates and short ton price of NOx.
2) From the ISO-NE website, we leveraged the wholesale ancillary and load charges, ISO-NE forward capacity market (FCM) net regional clearing price reports, effective charge-rate forecast, ISO-NE wholesale monthly reports by zone, New England Power Pool (NEPOOL) reliability committee/transmission Committee regional network service (RNS) Rates: 2020-2024 pooled transmission facilities (PTF) Forecast, ISO-NE regional network load (RNL) Reports.
3) Additionally, we also leveraged data such as the Henry Hub Natural Gas Futures Prices from NYMEX, Distribution Capital Expenditure Proxy Value from the Locational Value of Distributed Generation (LVDG) study and societal cost of carbon from the New York state website (NYS SCC)[1].

[1] New York DPS Societal Cost of Carbon

For data that was not publicly available, we gathered the relevant inputs through a combination of utility data requests and interviews.

<u>VDER Sensitivity Analyses</u>

Q. Please describe any sensitivity analyses you performed concerning the VDER Study.

A. As part of the VDER study, we conducted a sensitivity analysis to assess the impact of three factors on the DER avoided cost value stack. These sensitivities included (1) the impact of including consideration of environmental externalities, (2) the impact of high-load growth scenarios (HLGS) based on increased levels of building heating and transportation electrification, and (3) the market rate value scenario (MRVS) to determine the value of DERs that participate directly in the ISO-NE market (MRVS).

Environmental externalities are not currently applied in New Hampshire's utility system valuation and, therefore, are not currently included in the NEM tariff design. The Granite State Test (Primary) and the NH Utility Cost Test do not consider the impacts of non-embedded environmental externality. Thus, this avoided cost value was assessed as a sensitivity to the overall VDER assessment to determine how accounting for environmental externalities could impact the VDER results.

The AESC wholesale energy price forecasts include the costs of compliance with the Regional Greenhouse Gas Initiative (RGGI), therefore this cost was not included within the environmental externality sensitivity. For this analysis, the full social cost of CO2 emissions (net of RGGI compliance costs to avoid double-counting) is included in the environmental externalities value. Additionally, the AESC wholesale energy forecasts do not include any costs associated with NOx emissions. Therefore, the analysis assumes the full social cost of NOx emissions in the environmental externalities value.

The environmental externalities value does not include sulfur dioxide (SO2) emissions, particulate matter, and methane. The AESC assumes that coal-fired power generation, which is the primary source of SO2 emissions and particulate matter from electricity generation, will be phased out by 2025. Therefore, the environmental externalities value of these emissions is expected to be minimal. Although there may be potential significant costs related to methane emissions, as forecasting methane emissions for ISO-NE poses challenges, it was not included in the value of environmental externalities.

The HLGS sensitivity analysis assessed the incremental impact of varying the deployment of building and transportation electrification technologies on the avoided costs. The base-case value stack avoided costs are derived using the AESC 2021 study, counterfactual #2 scenario, which does not include programmatic resource impacts of building electrification but does include a projection of transportation electrification. As summarized in Table 1, three HLGS treatments were applied, accounting for (1) the impact of building electrification (derived from the AESC study counterfactuals #3 and #4) coupled with base-case projections of transportation, (2) the impact of building electrification coupled with more rapid electrification of transportation, and (3) further increased levels of building electrification coupled with more rapid electrification of transportation.

Table 1. Summary of HLGS Sensitivity Analyses and Data Sources

Scenario	Building Electrification (BE)	Transportation Electrification (TE)
Scenario 1: Impact of BE	AESC[2]	AESC[3]
Scenario 2: Impact of BE and high TE	AESC[2]	High[4]
Scenario 3: Impact of high BE and high TE	High[5]	High[4]

In Table 1 above, building and transportation electrification rates are varied under multiple scenarios under the HLGS sensitivity analysis. The sensitivity analysis assumed two levels of electrification: 1) Aligned with the AESC and 2) High case that assumes higher electrification rates than assumed in the AESC.

Each HLGS treatment applied volumetric and capacity avoided cost impacts as derived from the AESC counterfactual values and applied elasticity factors to extrapolate the avoided cost impacts for electrification levels that exceeded those presented in the AESC 2021 study

[2] **Building Electrification (AESC):** The AESC counterfactual #2 did not include the programmatic resource impacts of building electrification measures, but these impacts were included in counterfactuals #3 and #4. The building electrification measure impact included in counterfactuals #3 and #4 was added to counterfactual #2 to derive Scenario 1.
[3] **Transportation Electrification (AESC):** The AESC included transportation electrification impacts across all four counterfactual scenarios, so some degree of transportation electrification was considered in the base avoided cost values taken from the AESC counterfactual #2 scenario.
[4] **Transportation Electrification (High):** For HLGS scenarios 2 and 3, transportation electrification was assumed to exceed the AESC assumptions such that light-duty vehicle uptake aligned with a market share target of 26% by 2026, 90% by 2030, and 100% by 2035. Data availability on medium- and heavy-duty vehicle stocks and sales in New Hampshire was limited, so market share targets could not be established. Deployment was instead accelerated over AESC assumptions to align with the modified uptake trends in the light-duty sector, resulting in load impacts that exceeded AESC values by up to 58% at the mid-point of the study, but were approximately aligned with AESC assumptions by 2035.
[5] **Building Electrification (High):** The high building electrification assumptions included an accelerated timeline for heat pump installations in residential buildings, exceeding AESC assumptions by up to 30% at the study mid-point and 14% by the study end point.

results. HLGS impacts on environmental externalities were also assessed, applying regression analysis to the marginal emissions rates as published in the AESC 2021 study. Unlike the other two sensitivity analyses, the MRVS did not assess the sensitivity to potential variability in the avoided costs. The MRVS assessed the impact on the compensation received by a DER provider by participating directly in the wholesale power market operated by the ISO-NE rather than being compensated by the NEM tariff. The MRVS analysis quantified the resulting compensation the DER provider would receive based on the wholesale values of energy, capacity, and ancillary services.

VDER Study Findings

Q. Please provide a brief summary of the findings of the VDER Study.

A. In New Hampshire, DERs are forecasted to achieve a total average annual net avoided cost value of $0.13 to $0.19 per kWh of electricity produced in 2024 and $0.10 to $0.23 per kWh produced in 2035 (all values in 2024 $), varying by DER system type and excluding environmental externalities.

The two largest drivers of total technology-neutral value are avoided energy costs and avoided transmission charges. Avoided energy cost contributes up to 50% of the total technology-neutral value, and the contribution of this value declines over time. Transmission charges are forecasted to increase over time, increasing from 20% of the value stack ($0.02 per kWh) in 2024 to 38% ($0.05 per kWh) by 2035.

Net-metered DERs are expected to provide some additional value beyond what was shown in graphs and charts in the report, notably for those value stack criteria addressed qualitatively in this study: transmission capacity (for non-pool transmission facilities), transmission and distribution system upgrades, distribution grid support services, and resiliency.

Q. Please provide a brief summary of the findings in the VDER Study regarding rate and bill impacts.

A. The Rate and Bill Impact (RBI) analysis provides insight into the impact of DG deployment in New Hampshire on ratepayers, considering both the benefits and the costs that would be incurred by the utilities. The assessment is intended to serve as a future-looking estimate of the direction and magnitude of the impacts of DG deployment on all ratepayers and any potential cost-shifting between DG customer-generator and non-DG customer. It is not intended to represent an exact projection of future electricity rates and cost recovery. Instead, it serves as a future-looking approximation of the impacts on ratepayers attributable to DG. The RBI assessment highlights the impacts across the three regulated electric utilities serving New Hampshire - Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource), Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (Liberty) and Unitil Energy Systems, Inc. (UES) across three representative rate classes for each utility (residential, small general service, large general service) and three representative customer groups (typical DG customer-generators, typical non-DG customers, average utility customers). The average utility customer is not a customer class *per se* but is used to represent the resulting bill impacts in aggregate for all DG customer-generators and non-DG customers combined. The analysis considers the impacts under two scenarios for DG compensation: (1) Net Energy Metering (NEM), the existing alternative net metering tariff (effective September 2017), and (2) Avoided Cost Value (ACV) Tariff: a hypothetical tariff structure based on the outcomes of the VDER study where DG customer-generators are compensated for grid exports at the value of the avoided cost values. The RBI assessment was not updated to reflect the latest avoided costs published in the addendum.

Under the current NEM scenario, based on the forecasted DG adoption over the 2021 to 2035 period, on average, residential customers across the state are projected to experience a decrease of 1.0% in their monthly bills, while on average across small general service and larger general service customers are projected to experience a 0.5% and 1.8% reduction in their monthly bills.

While DG customer-generators will experience notable decreases in their monthly bills resulting from the NEM tariffs, non-DG customers are expected to experience a slight increase in their monthly bills, averaging 1.0% for residential customers and 0.5% for small and large general service customers. These bill increases for non-DG customers are driven by progressive increases in rates, which by 2035 results in a 1.2% to 1.8% increase in rates for residential customers, a 0.3% to 1.1% increase for small general service customers, and a 0.2% to 1.1% increase for large general service customers, depending on the utility service territory.

The ACV Tariff scenario yielded similar results to the NEM scenario, with the avoided cost-based compensation slightly reducing the bill impact on non-DG customers.

Q. Please describe any findings in the VDER Study regarding potential cost-shifting between net metering customers and non-net metering customers.

A. Under both RBI scenarios, non-DG customers are expected to experience minimum bill increases over the 15-year period, while DG customer-generators will experience notable bill reductions, suggesting the potential for relatively limited cost-shifting between these two customer groups. Note that if the avoided cost criteria identified as unable to be quantified were included and/or the environmental externality avoided costs were included, the bill impacts to non-DG customers are expected to be even smaller or reversed.

Q. Please provide a brief summary of the VDER Study Addendum that was filed in this docket on June 8, 2023, at Docket Tab 43.

A. Since the completion of the New Hampshire Value of Distributed Energy Resources Study Report in October 2022, natural gas prices have experienced a much higher increase than had been projected at the time of the study, driven to a large degree by the Russian invasion of Ukraine. The Addendum applies updated natural gas prices to adjust the Avoided Energy Costs, Ancillary Services and Load Obligation Charges, Transmission and Distribution Line Losses, Wholesale Market Price Suppression, and Wholesale Risk Premium to factor in the higher natural gas prices and convert them to the real $2024 values. The remaining avoided cost components were updated to reflect $2024 values. Compared to the original technology-neutral value stack, the total avoided costs (excluding environmental benefits) are, on average, about 17% higher in 2025 and about 5% higher by 2035.

The RBI assessment was not updated to reflect the latest avoided costs published in the addendum. Among the updated avoided cost streams, Avoided Energy Costs, Ancillary Services and Load Obligation Charges, Transmission and Distribution Line Losses and Wholesale Risk Premiums are a pass-through to retail customers and any reduction will not affect rates. The post-DG generation rate accounts for the impact of only those avoided-cost components that impact the generation rate; these include Avoided Capacity and Wholesale Market Price Suppression. Since updated Wholesale Market Price Suppression values are slightly higher than those in the original study, theoretically, the total avoided costs would be slightly higher, leading to lower fixed-cost recovery and reducing the upward impact on rates. However, since Wholesale Market Price Suppression benefits are a marginal component in the value stack – the impact on the RBI results would be minimal, which is why we did not update the RBI assessment.

VDER Study Model

Q. Did you provide a model associated with the VDER Study?

A. Yes, an Excel model was provided to the New Hampshire Department of Energy.

Q. What was the purpose of the model provided?

A. The Value of Distributed Energy Resource (VDER) Model is an Excel-based valuation tool that allows users to calculate the avoided costs of various DERs under the base case and three high-load growth scenarios. In line with the study, the model outputs the hourly avoided costs for thirteen components across the study period (2021 to 2035) for distributed energy resources such as solar, energy storage and small hydro as they are deployed for residential, commercial, and front-of-the-meter systems.

Q. Please briefly describe the model associated with the VDER Study.

A. The Value of Distributed Energy Resource (VDER) Model is an Excel-based valuation tool that allows users to calculate hourly, seasonal, or annual avoided costs for thirteen avoided cost components for a DER over a period of 15 years (2021 to 2035). The model can evaluate the avoided costs for a distributed energy resource under various building and transportation electrification scenarios. The following cost components are quantified in the model: avoided energy, avoided capacity, avoided ancillary services and load obligation charges, avoided RPS compliance charges, avoided transmission charges, avoided distribution capacity costs, distribution system operating expenses, avoided transmission and distribution line losses, wholesale market price suppression benefits, avoided wholesale risk premium, distribution utility administration costs and environmental externalities. Avoided transmission capacity, avoided transmission and distribution system upgrades, distribution grid support services, and resiliency services were not quantified but qualitatively addressed in the study report. Customer net installed costs were not quantified in the model but calculated in the report. Eight example DERs are pre-populated in the model: small hydro, behind-the-meter residential south-facing solar, behind-the-meter residential west-facing solar, behind-the-meter commercial south-facing solar, behind-the-meter commercial west-facing solar, front-of-the-meter solar, behind-the-meter residential south-facing solar coupled with energy storage and behind-the-meter commercial south-facing solar coupled with energy storage. For each example DER, the model is populated with representative hourly energy output values for the first eight resources. The model also includes two placeholders for the user to define an additional DER resource and evaluate the avoided cost value associated with a customized DER generation profile.

To run the model in the model Dashboard, the user needs to select the preferred DER resource, define the load growth scenario and tweak the sensitivity assumptions. The model allows users to assess the sensitivity of the results to various inputs. For example, the user can adjust the value of each avoided cost component and assess its impact on the total technology-neutral value stack. The user can set reasonable upper and lower values for each avoided cost and see how changes in specific avoided costs, or combinations, affect the overall system value.

Net Metering Compensation

Q. Does the VDER Study take a position on net metering compensation structure?

A. The VDER Study does not take a position on net metering compensation values or structure.

Q. Does this conclude your testimony?

A. Yes.