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

Docket No. DE 16-576

Development of New Alternative Net Metering Tariffs
and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators

# JOINT STAKEHOLDER COMMENTS ON THE PROPOSED SCOPE OF THE VALUE OF DISTRIBUTED ENERGY RESOURCES STUDY

Acadia Center, The Alliance for Solar Choice, Borrego Solar**,** the City of Lebanon, Conservation Law Foundation, the Energy Freedom Coalition of America, Granite State Hydropower Association, New Hampshire Sustainable Energy Association, ReVision Energy, and Vote Solar (collectively, the "Joint Stakeholders") appreciate the opportunity to comment on the proposed scope of the planned value of distributed energy resources (DER or VDER) study. We hereby provide these consolidated joint comments responding to the May 8, 2018 Value of Distributed Energy Resources Study Scope and Timeline Report (Staff Report).

We have appreciated the opportunity to develop consensus-based positions on the scope of the study in connection with expert assistance and under Staff guidance. This has been a fruitful exercise, as demonstrated by the substantial number of items in the Staff Report on which the parties have reached consensus. The Joint Stakeholders concur with the Staff Report in all but a few areas.

It is our understanding that all parties take the position that there should be further meaningful opportunities for input from stakeholders as the scope of the study is fleshed out by the independent consultant retained by the Commission. In particular, it would be appropriate to convene one or more technical sessions (or working group meetings) after the consultant is retained but before final decisions are reached as to the specific details of the study. This will not only provide an appropriate opportunity for stakeholder input, it will enable an exchange of initial information with the consultant on topics including the categories of data that can be collected and made available by distributed energy installers and the utilities.

In general, the Joint Stakeholders recommend that the independent consultant be given a measure of latitude to assess the scope of the study after selection and retention. For example, we recommend that the consultant be given latitude to assess whether additional sensitivity analyses may be effective and appropriate, and whether more precise values are possible (within a reasonable time and cost), for factors where proxies are currently recommended. In particular, we recommend that the consultant be granted flexibility to determine whether to conduct sensitivity analyses under scenarios that project higher levels of DER penetration. A sensitivity analysis on this subject would be an easy choice if it does not present a significant additional cost, and may provide useful information in the event that DER penetration levels increase unexpectedly due to factors such as new legislative directives or decreased costs of installation. The consultant is best-positioned to assess the cost of such an exercise. Alternatively, the Commission may wish to include this in the scope of the study, on the condition that the cost is reasonable.

As for whether and how to fold the pending locational value study into the general value of DER study, we believe that this decision should likely be made subject to further discussions in the Locational Value Working Group. To the extent that the locational value study includes one or more demonstration projects, it may be appropriate to treat the study like other pilots, which will help inform and provide data for the VDER study.

Finally, before we move to detailed comments on the Staff Report, the Joint Stakeholders would like to request that the Commission make an important clarification. In the working group meetings on the scope of this study, the parties have discussed the advantages of maximizing the technology-neutrality of the study's framework. While there may be certain values that are necessarily resource-specific, the consultant may be able to develop a framework for valuing multiple types of DER, such as by allowing input of different production profiles. Such a framework would be cost-effective and position the state well for the future.

Our understanding is that the parties continue to agree with the priorities set forth in Order No. 26,029, which directs that (at 60), "[t]he study should focus primarily on solar photovoltaic systems and hydroelectric facilities." However, the Joint Stakeholders believe that there may be ways for the DER study to be conducted that will make it more useful to the state by establishing a broader valuation framework. Specifically, the Commission should direct the independent consultant to determine the extent to which any valuation formulae can reasonably be made open to additional or alternate variables, so that for example we can more readily achieve not just a solar valuation, but a valuation of solar plus storage, solar plus locational value, or potentially renewable-fuel-based combined heat and power (CHP).

The Joint Stakeholders provide detailed comments below that primarily address areas where complete consensus has not yet been achieved.

**Pragmatic Concerns: Cost and Time**

Staff and the stakeholders have wrestled in earnest with a practical question: how to keep the costs and length of the study reasonable. As a result of our good-faith discussions on this subject, in a number of instances the parties have agreed to use qualitative-quantitative proxy estimates. This approach may have a number of benefits where, for instance, New Hampshire-specific data is limited, or where data is available but it would consume an excessive amount of time and money to produce a result that is precise. While it is important to maintain as much accuracy as reasonable and possible, in some cases perfection can be the enemy of the good.

It is well-established that proxy values can sometimes be appropriate in valuation processes like this one. Likewise, it is well-established that no material, non-zero values should be excluded completely from such a valuation. The National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, which presents a Resource

Valuation Framework prepared by the National Energy Efficiency Screening Project, includes this point among its six so-called "Universal Principles" for evaluating cost-effectiveness. With regard to "Hard to Quantify Impacts," the Manual explains:[1]

> Cost-Effectiveness practices should account for all relevant, substantive impacts (as identified based on policy goals,) even those that are difficult to quantify and monetize. Using best-available information, proxies, alternative thresholds, or qualitative considerations to approximate hard-to-monetize impacts is preferable to assuming those costs and benefits do not exist or have no value.

As the Manual suggests, it would be illogical, and potentially grossly misleading, to apply a zero value to (or to ignore entirely) any relevant and material value that is known to be non-zero. The Joint Stakeholders concur with the Manual, and with the Staff Report in this docket, that it is important to include material but hard-to-quantify impacts, even if a proxy estimate provides the greatest degree of accuracy that we can reasonably achieve at this time.

In cases where proxy estimates will be used, we recommend that the Commission direct the independent consultant to assess – and provide a list of if possible – what information may be collected in the future in order to provide more accurate data in any further studies.

**Cost-Benefit Analysis**

The Joint Stakeholders urge the Commission to carefully consider the appropriate cost-benefit tests before launching the value of DER study. In Order No. 26,029, consistent with prior Staff recommendations, the Commission stated that the value of DER study should "incorporate[e] both TRC and RIM test criteria." We urge the Commission to eliminate the Ratepayer Impact Measure (RIM) Test to better achieve the state's goals. Recent analysis shows that the Utility Cost Test (UCT), combined with a customer bill impact analysis, are superior to the flawed RIM test.

In accordance with the Commission's Order and HB 1116, there are three goals that the state wishes to achieve through cost-benefit analysis. They are:

(1) to indicate how DER will affect participants and state policy goals,
(2) to determine how DER will reduce total utility costs, and
(3) to identify how DER will affect non-participating customers (including whether there may be a "cost-shift").

We agree that if the state can get a good picture of these three impacts, it will have a strong sense of the cost-effectiveness and impacts of DER and how to set the level of compensation.

To best achieve these three goals, the Joint Stakeholders recommend that the Commission direct as follows. First, to indicate how DER will affect participants and state

[1] National Standard Practice Manual (Spring 2017), National Efficiency Screening Project, available at: https://nationalefficiencyscreening.org/national-standard-practice-manual/.

policy goals, the consultant should apply the Total Resource Cost (TRC) Test, plus environmental and public health externalities, consistent with Order No. 26,029 and Staff's recommendations under Box 16 ("Externality Benefits" at p. 12). Second, to determine the impact of DER on the utility system as a whole, the consultant should conduct a Utility Cost Test. Third and finally, in order to identify how DER will affect non-participating customers, including any potential for cost-shifting, a bill impact analysis of a customer's entire bill should be completed.

The RIM Test has recently been discredited by leading experts in the field of cost-benefit analysis. By way of background, the parties in Docket DE 17-136 (EERS implementation docket) are considering potential updates and modifications to the state's cost-benefit analysis practices in a Cost-Benefit Working Group. Commission Staff recently invited Tim Woolf of Synapse Energy Economics, Inc., a leading expert in the field of cost-benefit analysis, to present to that Working Group on the subject of cost-benefit tests and their appropriate uses. Subsequently, Mr. Woolf also was invited by the Chair of the EESE Board, Donald M. Kreis, to present on the same subject to that body. While the Cost-Benefit Working Group in DE 17-136 has not concluded its discussions on the subject of cost-benefit tests, these presentations gave the parties a great deal to consider. Some of that information is also relevant to distributed energy resources. In particular, Mr. Woolf stated that the RIM Test was not a reliable or appropriate test and should "never" be used to assess the cost-effectiveness of a resource.

In 2016, Synapse cost-benefit experts, among them Mr. Woolf and four other authors, published a white paper entitled "Show Me the Numbers: A Framework for Balanced Distributed Solar Policies"[2] that contains analysis similar to Mr. Woolf's presentation to the EERS Cost-Benefit Working Group and the EESE Board, as applied to DER. On the subject of the Rate Impact Measure Test, the report makes the following findings:

> The purpose of the Rate Impact Measure (RIM) Test is to indicate whether distributed solar resources will increase or decrease electricity rates (i.e., prices). This test is sometimes used to indicate the impacts on non-solar customers, because these customers might experience rate impacts as a result of generation from distributed solar facilities. However, as explained more below, the RIM Test has several fundamental flaws and should not be used to evaluate rate impacts. Instead, a more comprehensive rate and bill impact assessment should be performed (as discussed in the following chapter).
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> One of the main limitations of the RIM Test is that it conflates cost-effectiveness and cost-shifting. These are two separate effects that can only be fully understood with separate analysis. Cost-effectiveness analyses should include only future costs, and should seek ways to minimize those future costs (along with achieving other policy goals). The RIM Test includes lost revenues, which are a result of historical costs (i.e., sunk costs) that are embedded in electricity rates. These costs would

[2] Available at http://www.synapse-energy.com/sites/default/files/Show-Me-the-Numbers-16-058_0.pdf.

exist with or without distributed solar, and therefore are not a new cost to the utility system caused by distributed solar.

> Combining future costs and historical costs in one test makes it difficult to understand either cost-effectiveness or cost-shifting. It is also inconsistent with standard microeconomic theory, which requires that sunk costs not be included in cost-effectiveness analyses.
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> Further, the RIM Test does not provide the information that utilities and regulators need to assess the magnitude of rate impacts caused by distributed solar resources. This test simply indicates whether rates will increase or decrease as a result of these resources. A RIM Test might result in a benefit-cost ratio of 0.9, for example, but this does not provide any indication of whether the rate impact is significant or de minimus. In other words, it provides no information regarding whether the rate impacts are likely to be reasonable, given the other benefits of distributed solar resources. A separate rate impact analysis, described in Section 5 below, can provide more useful metrics for this purpose, such as the percent change in rates or the average change in customer monthly bills.

The State and Local Energy Efficiency Action Network, a working group facilitated by the Department of Energy and the EPA to support state and local energy efficiency efforts, similarly repudiated the RIM Test. In a July 2011 report entitled "Analyzing and Managing Bill Impacts of Energy Efficiency Programs," that working group warned as follows (citation omitted):[3]

> It is important to note at the outset that the Ratepayer Impact Measure (RIM) Test…is an insufficient way to assess rate and bill impacts. It is overly narrow, ignores many of the benefits of energy efficiency programs, is inconsistent with the assessment of supply-side resources, does not necessarily reflect the actual impact on rates, and deprives customers of the opportunity to lower their bills through energy efficiency measures.

In a 2013 article on valuing energy efficiency published in Public Utilities Fortnightly, Hossein Haeri and M. Sami Khawaja of Cadmus Group advised that, "The RIM test … is a blunt instrument…. Since most energy efficiency programs fail the test, it's unclear what policy guidance the test's outcomes might offer."[4] The Joint Stakeholders do not believe the test offers helpful policy guidance for DER either.

In short, the RIM Test has generally been discredited because it suffers from several fatal flaws and does not achieve the goals it purports to achieve. It includes sunk costs, which should not be used to assess future resource investments because they will occur regardless of whether the future investment is undertaken. Benefit cost-analyses typically include the comparison of a business-as-usual case with another case that includes some amount of DER. The net impacts

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[3] Available at https://www4.eere.energy.gov/seeaction/sites/default/files/pdfs/ratepayer_efficiency_billimpacts.pdf.

[4] Hossein Haeri & M. Sami Khawaja, *Energy Efficiency: The Search for a Better Yardstick*, Public Utilities Fortnightly (July 2013), *available at* www.cadmusgroup.com/wp-content/uploads/2013/07/Valuing-Energy-Efficiency-Haeri_Khawaja.pdf.

are identified by taking the difference between the two cases. The lost utility revenue will be recovered from ratepayers in both cases. As a result, it does not make sense, and will produce misleading results, to include these costs in one of the cases but not the other.

In contrast, any investment that passes the Utility Cost Test will result in cost reductions. For this reason, the Utility Cost Test should be substituted for the RIM Test, and can be combined with a rate impact analysis in order to address both the second and third goals of cost-benefit analysis here – that is, to determine both the impacts on total utility costs, and the impacts on non-participating customers.

The Utility Cost Test indicates the extent to which distributed solar or other DER will reduce total electricity costs to all customers by affecting utility revenue requirements.[5] The Utility Cost Test should include all utility system costs that impact revenue requirements when additional DER is added to the system.[6] The utility system costs are comprised of all costs that the utility must recover from customers, such as net metering administration costs, interconnection costs beyond what is borne by the customer, and distribution system upgrades. The Utility Cost Test should also include all utility system costs that are avoided by the distributed solar resource, including avoided energy costs, avoided generation capacity, market price suppression effects, avoided transmission and distribution costs, avoided line losses, and avoided environmental compliance costs. The purpose of the Utility Cost Test is to indicate whether a resource's benefits will exceed its costs from the perspective of the utility system.

According to the 2016 Synapse report:[7]

> The key advantage of the Utility Cost Test is its simplicity; it indicates how distributed solar resources will affect electric utility costs to all customers as a whole. It is the methodology that utilities have used for years to assess the costs and benefits of electricity resource investments, and is the primary criterion for assessing costs and benefits in the context of integrated resource planning.

In addition, a customer bill impact analysis should be used to address both bill impacts and participation impacts. Bill impacts provide an indication of the extent to which customer bills may increase or decrease. This includes both those customers that install DER and those that do not. Taken together, bill and participation factors indicate the extent to which customers will be impacted (positively or negatively) by DER investments, and the extent to which DER may lead to distribution equity concerns. For reference, Chapter five of "Show Me the Numbers:

[5] "Show Me the Numbers" at 2.
[6] *Id.* at 23.
[7] *Id.* at 24. The report finds the UTC to be limited in one major respect: "One key limitation of the Utility Cost Test is that it does not reflect the extent to which distributed solar resources will achieve energy policy goals (except for the goal of reducing costs). Most jurisdictions establish distributed solar policies for the explicit purpose of increasing fuel diversity and independence, reducing environmental impacts, and increasing local jobs and economic development. The Utility Cost Test, by design, does not reflect these types of benefits." In order to assess these additional factors, the TRC Test can be used in parallel. "The main advantage of the TRC Test is that it provides more comprehensive information than the Utility Cost Test, by including the impacts on participating customers. In this way the 'total cost' of the resource is reflected in the test, regardless of who pays for those costs." *Id.* at 25.

A Framework for Balanced Distributed Solar Policies" discusses cost-shifting and rate impact analyses.

A customer bill impact analysis can also help indicate the extent to which all customers have reasonable access to DER. Customer participation information can indicate the extent to which customers of various types are engaging with DER. If information on customer participation is not currently available, it should be collected in order to ensure equity and to ensure that the state is achieving the goal set forth in HB 1116 to provide reasonable access to DER.

For these reasons, the Joint Stakeholders advise the Commission to direct the consultant to apply the TRC Test including externalities, but to substitute the Utility Cost Test plus a bill impact analysis for the inappropriate and unreliable RIM Test. This will more effectively achieve the established goals of the VDER study.

**AESC Data**

At the June 29, 2018 public comments hearing, Mr. Fossum of Eversource suggested that the Commission should give serious thought whether to rely on the Avoided Energy Supply Components in New England (AESC) study.[8] Mr. Fossum suggested that the AESC study may be applicable only to energy efficiency, not DER. This criticism of the Staff Report, which recommends using the AESC study in a number of instances, is simply unreasonable. The AESC energy and generation capacity analyses in particular are valuable and costly resources that need not be duplicated.

The AESC study prepared by the AESC 2018 Study Group for use by the New England states, and updated on March 30, 2018 (with June 1 amendments), is generally considered a definitive study. It is relied on by this state and a number of other states for energy efficiency valuation, but its use is not limited to energy efficiency. The AESC study evaluates a number of costs that can be avoided by load reductions of various types. For instance, it contains avoided energy values by hour that can be used in valuing load-reducing energy resources not limited to energy efficiency but also including energy storage, load management techniques, rate programs like critical-peak pricing, and distributed energy resources including rooftop solar. It would be a waste of limited resources to repeat this undertaking and is not necessary. We concur with Staff.

**Transmission Charges – Item No. 5**

Transmission charges and future forecasted expenses should be part of the study scope. Green Mountain Power in Vermont has designed customer-facing programs to manage transmission expenses and New Hampshire is considering a similar effort proposed by Liberty Utilities. While these charges do not go away and are allocated based on coincidental peak, it is important to assess impacts and strategies that different utilities may deploy in order to

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[8] SYNAPSE ENERGY ECONS. ET AL., Avoided Energy Supply Components in New England: 2018 Report (June 1, 2018) *available at* www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf.

understand the impacts and benefits. Forecasted expenses will be directly affected by the regions transmission capacity needs and the non-transmission alternative benefits that DERs can provide.

**Transmission Capacity – Item No. 6**

The transmission capacity value should be quantified and included as an avoided cost to the utility based on the quantified value of avoided and deferred transmission costs. Excluding this avoided cost from the scope of the study would eliminate an important data point from consideration. DER like rooftop solar are load-reducing, which provides value to the energy system and to ratepayers by avoiding additional transmission capacity costs. To the extent that avoided transmission capacity costs cannot be reasonably and cost-effectively estimated by a quantitative analysis at this time, qualitative criteria and suggestions for proxy or estimated values should be explored by the independent consultant.

The Joint Stakeholders agree with the Staff Report recommendation to consider a qualitative-quantitative proxy estimation approach. This approach can provide additional data points and information for stakeholders and decision makers to inform tariff development moving forward, reveal additional values that would otherwise remain unknown, and provide an important placeholder for future quantitative research.

**Distribution System Operating Expenses – Item No. 8**

Joint Stakeholders agree with Staff's recommendation that a qualitative-quantitative proxy estimate approach should be used to determine avoided distribution system expenses. The VDER study is well-suited to assess DER capabilities, as discussed in No. 17 (Distribution Grid Support Services), and to translate those capabilities into a value assessment for the multiple "stacked" service capabilities that DER, such as solar co-located with storage, can provide to defer distribution system expenses. For example, DER telemetry data can reduce utility expenses during outage investigation/recovery and assist with grid operations by telemetering data to the utility. Alternatively, enhancing DER coordination with utilities Volt/VAR optimization strategy can reduce line losses and demand from ISO-NE as a specific grid service that can be leveraged to defer or avoid certain distribution system expenses. These values should be assessed and quantified, or a proxy estimate should be applied to reflect the distribution system operating expenses that can be deferred.

To the extent that some of DER capabilities identified in Item No. 17 can be provided by specific DER configurations that are not included in the VDER determination, the Joint Stakeholders recommend that these incremental service values be incorporated in VDER grid service rider tariffs specific to the incremental service/value that certain DER configurations can provide. This study should examine these additional opportunities and values pursuant to the assessment conducted in Item No. 17 and begin gathering the data needed to establish VDER grid service rider tariffs following the establishment of the VDER.

**Hedging/Wholesale Risk Premium – Item No. 12**

The Joint Stakeholders support Staff's recommendation for a qualitative-quantitative proxy estimate to evaluate the impact of DER on hedging/wholesale risk premiums. The fact that distribution utilities do not pay any hedging costs for energy supply is irrelevant to the fact that competitive suppliers undoubtedly do include some risk premium or hedging costs in their bids for forward fixed price default service, due to uncertainty or risk regarding both the amount of load to be served and the future cost of electricity supply as reflected in day-ahead and real-time wholesale energy markets. As described in the Staff Report, this avoided cost is the potential "[a]voidance of risk premium applicable to retail sales relative to wholesale market price exposure, as included in default service bids." Report at 10.

While the absolute value of such risk premiums may be difficult to discern, as they are comingled with bidder's overhead and profit, the spike in default service bids that occurred after the polar vortexes that occurred during the winters of 2013–2014 and 2014–2015 when wholesale market prices spiked to very high levels (and to a much lesser extent at the end of 2017 and early January of this year) is an indication of the increase in such hedging/risk premium costs. It is significant to note that actual wholesale prices stayed rather low during the winters of 2015-2016 and 2016-2017, creating a larger than usual spread between forward fixed prices in the form of default service bids and actual wholesale costs.

The Commission could choose to give the consultant confidential access to the confidential information regarding default service bids and the various confidential components thereof (such as RPS compliance costs) which might help the consultant tease out the amount of hedging costs embedded in those bids. A qualitative review of literature and the characteristics of DERs and how they may affect risk premiums can consider how DERs may reduce load risk and temper fuel supply cost risks and volatility as DERs either function as low reducers or, if participating in wholesale markets, as generally fuel cost free price takers that reduce the amount of supply procured that has fuel cost risk. In effect DERs may act as physical hedges against fuel and wholesale market price volatility in lieu of financial hedging. The AESC study assumption of 8%, as a regional value, also merits review and consideration as a low-cost proxy for a New Hampshire-specific value. A New Hampshire-specific value may not be necessary as the wholesale and energy supply markets largely operate on a New England regional basis and such a regional proxy may mitigate the potential cost of a consultant trying to develop a New Hampshire-specific estimate.

**T&D System Upgrades – Item No. 14**

The Joint Stakeholders recommend including in this assessment the transmission and distribution system upgrade savings that can be achieved from the presence of DER and the DER grid service capabilities identified in Item No. 17 (Distribution Grid Support Services) to the extent that these savings are not quantified in the other categories. For instance, the benefits that accrue from passive presence of DERs and the benefits that accrue from the active management of specific DER capabilities to provide specific grid services (such as increased hosting capacity through integrated DER management) create value through transmission and distribution system upgrade savings. These savings benefits should be included here to provide a more accurate assessment of costs and benefits of DERs to transmission and distribution system upgrades. A higher level of DER penetration is not directly related to higher utility costs for system upgrades, as enhanced DER coordination and operations management can provide, for instance, DER hosting capacity expansion that reduce utility upgrade costs and provide additional grid savings benefits.

**Utility Lost Revenues – Item No. 15**

While the Joint Stakeholders agree that Utility Lost Revenues are within the scope of the study, we disagree with Staff's recommendation that no consideration be given to how potential increased electrical usage caused by or correlated with the adoption of distributed generation may impact lost utility revenue. This does not need to be a difficult or costly analysis as Staff asserts because the data should be readily available to discern whether or not there is a correlation between increased customer gross electricity consumption and adoption of net metered distributed generation. The assumption thus far regarding utility lost distribution revenue is that the lost volumetric electricity sales equals the gross behind-the-meter distributed generation production (as estimated using PV Watts for solar pursuant to Order No. 25,991, February 21, 2017) plus the net volumetric sales from the utility. However, if net metered customer-generators increase their behind-the-meter electricity consumption, and such increase is statistically significantly greater than that of the customer class as whole, then the actual lost distribution revenues may more appropriately be represented by the difference between their average usage prior to net metering and their net sales from the utility after net metering.

There was significant unrebutted testimony provided on this issue in this proceeding and the Utility and Consumer Coalition (UCC) Settlement specifically called for the collection and analysis of such data. In Exhibit No. 25, the Direct Testimony of Clifton Below on behalf of the City of Lebanon, he noted that the lack of data on customer loads and load shape before and after adoption of net metered distributed generation limited the ability to analyze the various impacts of net metering. Noting that the New Hampshire Electric Cooperative has had the metering in place to understand load and load shapes of customer-generators both before and after adoption of net metering (because of their widespread deployment of interval production meters), unlike any of the parties in this proceeding, he observed that in

> . . . their "'Above the Cap' Net Metering Staff Analysis & Recommendations"[9] [. . .] "we found that, on average, we could attribute an increase in usage of about 52% to the PV accounts" (p. 3) negating some of what might otherwise be under-recovery of delivery charges. This seems to be evidence of PV adopters also adopting new forms of electrification, such as heat pumps and/or electric vehicles." (Ex. 5 at 9:262-265.)

In Exhibit No. 5 in this proceeding, the UCC Settlement Agreement (at 9), those parties agreed that:

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[9] See http://www.nhec.com/filerepository/nhec_above_the_cap_net_metering_recommendationsstaff_analysis_2.pdf.

> The Utilities agree to provide data on annual (12 month period) loads for net metered accounts for one or more years before they interconnect their net metered systems, where available, along with annual average loads for comparable time periods, before and after implementation of net metering, for customers who did not adopt net metering, so that the percent change in annual load for customers, by rate class, who did and did not adopt net metering, can be compared for comparable time periods.

While the Commission's Order No. 26,029 (June 23, 2017) did not specifically address this issue, the Commission did authorize the distribution utilities to provide customer-generators with revenue-grade production meters for renewable energy credit (REC) production, enabling such an analysis. The utilities possess individual customer account consumption data for some number of years before net metering under new alternative net metering tariffs. As utility production meters are installed for these net metered accounts the utilities will have the data for calculating customer-generators' actual gross behind-the-meter electricity consumption, which can be compared with their consumption before net metering, as well as for their customer class for comparable before and after time periods (which would allow for accounting of weather and other exogenous variables). A relatively simple analysis could tell whether there is in aggregate a statistically significant correlation between adoption of net metered distributed generation and a change in overall behind the meter electricity usage. While the reasons for such a correlation may be a more complex subject to analyze, the basic facts should be readily calculable and available to parties as part of a value of DER study.

There is an increasing awareness of "beneficial" or "strategic" electrification as a means to address or mitigate climate change, such as by converting vehicles and space and hot water heating from fossil fuels to cleaner electric power, as well as by using electric battery power for portable devices such as lawn mowers, chain saws, and weed whackers.[10] The markets for these technologies have been growing. There is a possibility that adopters of renewable net metered distributed generation are implementing climate action strategies such as beneficial electrification in their personal and business lives, particularly once they know most or all of their net electricity consumption is offset by a local renewable source.

The Commission's value of DER study does not need to make a quantitative analysis of causation in order to discern if there is a correlation. As for secondary

[10] The rise and benefits of strategic electrification have been described in a number of key articles and reports, including: Keith Dennis, Ken Colburn, & Jim Lazar, *Environmentally Beneficial Electrification: The Dawn of 'Emissions Efficiency'*, 29 ELECTRICITY JOURNAL 52 (2016), available at https://www.sciencedirect.com/science/article/pii/S1040619016301075; DANIEL STEINBERG ET AL., *Nat'l Renewable Energy Laboratory, Electrification & Decarbonization: Exploring U.S. Energy Use and Greenhouse Gas Emissions in Scenarios with Widespread Electrification and Power Sector Decarbonization* (July 2017), https://nrel.gov/docs/fy17osti/68214.pdf; and Sherri Billimoria et al., *The Economics of Electrifying Buildings*, ROCKY MOUNTAIN INSTITUTE (July 10, 2018), https://rmi.org/insight/the-economics-of-electrifying-buildings/.

impacts of such potential correlated increases in electricity use, those impacts could be a subject for future consideration but do not fall within the scope of the present study. Regardless, if such a correlation may exist, it does not make sense to simply ignore it—so that we cannot consider it now or in the future—given the ready availability of data to discern that correlation.

**Externality Benefits - Item No. 16**

Externality benefits, in particular public health and environmental benefits, should be evaluated within the distributed energy resources value stack. Public health and environmental benefits are well-established state policy objectives with respect to distributed energy resources and other low or non-emitting resources, therefore it would be inappropriate to exclude these benefits from the valuation study. Feasibility and cost do not present significant issues as to either. The Joint Stakeholders recommend that public health and environmental benefits be included within the value stack rather than a sensitivity analysis, because they are integral to state policy. However, we are alternatively willing to agree to Staff's compromise proposal, which would direct the independent consultant to evaluate public health and environmental externalities in a sensitivity analysis.

House Bill 1116, 2016 N.H. Laws Chapter 31 (HB 1116), in its legislative purpose, cites "environmental benefits" as a policy basis for the expansion of the net metering cap and the development of a new alternative net metering tariff. HB 1116 states that to meet the goals of developing competitive markets, promoting customer choice, energy independence and local renewable energy resources:

> it is in the public interest to continue to provide reasonable opportunities for electric customers to invest in and interconnect customer generator facilities and receive fair compensation for such locally produced power while ensuring costs and benefits are fairly and transparently allocated among all customers, and the promotion of a balanced energy policy that supports economic growth and energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits, a fair allocation of costs and benefits, and a modern and flexible electric grid that provides benefits for all ratepayers.

Likewise, the Limited Electrical Energy Producers Act (LEEPA) states in its Declaration of Purpose that it is in the public interest "to encourage and support diversified electrical production that uses indigenous and renewable fuels and has beneficial impacts on the environment and public health." RSA 361-A:1.

Similarly, the Electric Renewable Portfolio Standard states that "it is in the public interest to stimulate investment in low emission renewable energy generation technologies" in part because such technologies "can reduce the amount of greenhouse gases, nitrogen oxides, and particulate matter emissions…thereby improving air quality and public health, and mitigating against the risks of climate change." RSA 362-F:1.

The Electric Utility Restructuring Act states that the overall public policy goal of restructuring is to, among other things, ensure "reliable electric service with minimum adverse impacts on the environment" and that competitive markets should provide "incentives to operate efficiently and cleanly." RSA 374:F-1.

In accordance with LEEPA and HB 1116, and consistent with state policy enshrined in other energy and environmental laws, the Commission ruled in Order No. 26,029 that public health and environmental externalities are within the scope of the upcoming value of DER study, provided that potential double-counting is addressed. The Commission found that that a value of DER study:

> may also include consideration of demonstrable and quantifiable net benefits associated with relevant externalities (such as environmental or public health benefits), provided that the potential for double-counting of such externalities is adequately mitigated. With respect to double-counting of externality benefits, if a potential DG benefit is included in wholesale electricity market price formation, either directly or indirectly, then it should not be included in the study scope. For example, all or part of the societal benefits of carbon reduction may be covered by the Regional Greenhouse Gas Initiative (RGGI) program, and RGGI costs incurred by fossil-fueled generators may effectively be included in the wholesale energy market bids of those generators. Under those circumstances, the resulting wholesale energy market prices would already incorporate those carbon reduction benefits and they would be taken into account through the energy component of the net metering credit and should not be counted as an additional benefit to be separately valued.

The utilities have suggested that any value is already captured by wholesale electricity costs or addressed by state or federal policies. However, previous analyses and studies conducted in other states have demonstrated that the full value of the environmental benefits associated with distributed renewable energy resources are not captured by the compliance costs associated with existing environmental programs such as the Regional Greenhouse Gas Initiative, Renewable Portfolio Standard, of the EPA Acid Rain Program.[11] The current programmatic costs of these programs are incorporated into wholesale electricity rates and therefore will be reflected in Item #1 – Avoided Energy Cost. However, to avoid doubled-counting, these costs can easily be subtracted from the total value of externalities quantified by the value of DER study, as they have been in studies conducted in other states.

For instance, the most recent auction prices for RGGI were $3.79 in March 2018 and $4.02 in June 2018.[12] The highest price was $7.50 in December of 2015. The cost containment

[11] ISO-NE stakeholders including Conservation Law Foundation, National Grid, NextEra, Brookfield Renewable, and RENEW: Northeast have worked with Brattle Group to propose a market solution to better value non-emitting energy resources for their contributions toward achieving policy goals, including public health and environmental goals, in the form of a Dynamic Forward Clean Energy Market. More information about that market solution is available at: http://files.brattle.com/files/11819_a_dynamic_clean_energy_market_in_new_england.pdf. However, this market solution has not yet been adopted. Wholesale market pricing currently does not fully reflect the value of various externality benefits particular to non-emitting resources.

[12] Auction Results, The Regional Greenhouse Gas Initiative (July 10, 2018), https://www.rggi.org/auctions/auction-results.

trigger price was $10 in 2017, rising at 2.5% until becoming $13 starting in 2021 (rising over time at 7%) to $23.89 in 2030.

In contrast, the EPA established a social cost of carbon at $36 per ton for 2015, rising to $50 per ton in 2030. The 2018 Avoided Energy Supply Components in New England (AESC) study utilized a different methodology based on marginal abatement costs, and found a total environmental cost of $100 per ton of $CO_2$ emissions based on global costs and $174 per ton of $CO_2$ emissions based on New England abatement costs. It also established a non-embedded $NO_X$ emission cost of $31,000 per ton of nitrogen based on a review of findings in the literature, which translates into a wholesale avoided cost for $NO_X$ of $1.65 per MWh.[13]

While market values and policies exist to address some public health and environmental benefits, they are clearly insufficient to capture the full value of the externalities, nor are they intended to fully capture it.

There is substantial precedent for developing such methodology based on subtracting quantifying the gap between the total value of the environmental benefits of DER and the value already captured in wholesale electricity costs. The New York Public Service Commission issued an order (RE: CASE 15-E-0751 and CASE 15-E-0082) recommended that resources shall receive the higher of the Tier 1 REC price (valued at $17.01/MWh in 2018)[14] or the Social Cost of Carbon, net of the expected Regional Greenhouse Gas Initiative (RGGI) allowance values, as calculated by Staff per the Benefit Cost Analysis (BCA) Framework Order.[15]

The Joint Stakeholders recommend including public health and environmental externalities in the value stack of the VDER study. In the alternative, we would be willing to accept a sensitivity analysis, as recommended by Staff in their May 8, 2018 report. The Staff report recommends that the appropriate analysis could include RGGI market price projections to determine embedded $CO_2$ costs, AESC non-embedded environmental costs and methodologies, AVERT model to determine any non-embedded NOx, $SO_2$ and particulate matter impacts, U.S. EPA social cost of carbon, and review of non-embedded methane emissions impacts.

We are aware from Unitil's comments to the Commission at the public hearing on June 29, 2018 that the utilities may prefer to avoid this subject entirely in the value of DER study because they believe the utilities are not likely to agree with the other parties. However, state policy supports the inclusion of public health and environmental externalities, and the Commission has already ruled that they may be considered in the study. Furthermore, Staff's proposed compromise of conducting a sensitivity analysis, combined with a transparent

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[13] *Id.*

[14] NYSERDA, 2018 Compliance Year (July 10, 2018), https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/REC-and-ZEC-Purchasers/2018-Compliance-Year.

[15] PSC, Order On Net Energy Metering Transition, Phase One Of Value Of Distributed Energy Resources, And Related Matters, New York Public Service Commission (September 14, 2017), http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A5F3592472A270C8525808800517BDD?OpenDocument.

comparison of how the analysis of these externalities compares to the values captured in avoided wholesale electricity costs, can hardly be objectionable.

**<u>Customer Installed Net Costs – Item No. 19</u>**

The Joint Stakeholders recommend eliminating customer installed costs as a category for study. The scope of the study should be confined to determining the value of the benefits that DER provide as compared with the utility costs associated with DER integration. The costs of private investments made by customers to install DER have no bearing on the value that DERs provide to the grid and other ratepayers, or the utility costs for integrating DER. This category should excluded from the study.

To the extent that Staff have included customer installed net costs in their recommended scope because Staff believe this data will help comply with HB 1116's mandate to provide "reasonable opportunities for electric customers to invest in DER," we alternatively suggest that providing reasonable compensation and appropriate price signals for the value of DER accomplishes this goal and was the intent of HB 1116. As a policy matter, the regulatory goal is to strengthen competition and reduce barriers, while ensuring customer education and access are sufficient, not to scrutinize prevailing investment costs. Reasonable opportunities to invest are appropriately gauged not through interference with private investment choices, but through (1) the removal of unnecessary or inappropriate obstacles to competition and customer access, (2) providing just compensation for benefits and services offered, and (3) assessing DER penetration levels and rates of change.

New Hampshire cannot change global supply chains costs, and should not seek to control local competitive markets in DER. However, by providing an accurate valuation of DER, this study can assist customers in identifying the most appropriate and cost-effective energy solutions that meet their needs and the needs of the state. Permitting costs are a variable that can be impactful and a cost under local jurisdiction. In order to better understand the financial impacts of permitting, the Commission should consider adding permitting costs to the study.

There are additional complications to including customer installed net costs for hydroelectric facilities. Unlike some other technologies, hydroelectricity has considerable ongoing operation, maintenance, and regulatory compliance costs, including permitting and federal licensing/relicensing costs, that can vary greatly depending on the particularities of individual projects. Further, in some cases the hydroelectric customer installed net costs were incurred decades ago, so that it does not make sense to include original construction and permitting costs.[16]

In the event that the Commission does determine that customer installed costs should be included in part of the study, those costs should be based on publicly available information, and a permitting costs assessment should be included within the scope to ensure valuable local information. Proprietary or otherwise private customer and installer information should be not required, and is not relevant to properly valuing the benefits that DER offers.

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[16] Such costs are generally very resource- and time-specific. As a result, they may not be particularly useful in a generalized study of costs and benefits.

Respectfully submitted,

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