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

Brief of the Energy Future Coalition

The Energy Future Coalition ("EFC" or "the Coalition"), consisting of Acadia Center, The Alliance for Solar Choice, Borrego Solar Systems Inc., Conservation Law Foundation, Energy Freedom Coalition of America, LLC, New Hampshire Sustainable Energy Association, Sunraise Investments LLC, Solar Endeavors LLC, ReVision Energy, LLC, and Revolution Energy, LLC, submits this post-hearing brief. In consideration of direction offered by the Public Utilities Commission ("Commission"), the brief will first suggest a rationale for the decision of the Commission, and then offer a more traditional legal brief with supporting references.

I. A RATIONALE FOR DECISION

The Limited Electrical Energy Producers Act ("LEEPA"), the mandates of HB 1116 and the clearly articulated policies affirmed by HB 1116 require exactly that the revised net metering program "... promote solar in the state." (Tr., 3/28/17 PM at 77). These statutory mandates and objectives include:

- HB 1116, finding that to "meet the objectives of electric industry restructuring pursuant to RSA 374-F, including the overall goal of developing competitive markets and customer choice to reduce costs for all customers, and the purposes of RSA 362-A and RSA 362-F to promote 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."[1]

- RSA 362-A:9, XVI, as enacted by HB 1116, directing the Commission "to develop new alternative net metering tariffs, which may include other regulatory mechanisms and tariffs for customer-generators, and determine whether and to what extent such tariffs should be limited in their availability within each electric distribution utility's service territory," and to consider "the costs and benefits of customer-generator facilities; an avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time based tariffs pursuant to paragraph VIII; … [and] timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism…"
- HB 1116, declaring that the "general court continues to promote a balanced energy policy that supports economic growth and promotes 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."[2]
- RSA 362-A:9, I, which provides, "Standard tariffs providing for net energy metering shall be made available to eligible customer-generators by each electric distribution utility in conformance with net metering rules adopted and orders issued by the commission…"

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[1] Laws 2016, Chapter 31, § 31:1.

[2] Id.

- RSA 362-A:9, III, requiring, "Metering shall be done in accordance with normal metering practices. A single net meter that shows the customer's net energy usage by measuring both the inflow and outflow of electricity internally shall be the extent of metering that is required at facilities with a total peak generating capacity of not more than 100 kilowatts…"
- RSA 374-F:3, finding, "Allowing customers to choose among electricity suppliers will help ensure fully competitive and innovative markets. Customers should be able to choose among options such as levels of service reliability, real time pricing, and generation sources, including interconnected self generation…"

In this determinative legal context, the Commission considers two proposals that are similar in important respects, both of which reduce the financial compensation received by customer-generators investing in Distributed Energy Resources ("DER") in New Hampshire. However, only the more gradual, moderate, and targeted EFC proposal satisfies and fulfills the statutory law, legislative policy, the premise of regulatory certainty, and continued implementation of New Hampshire's long-standing policy to encourage the development of DER.

The factual evidence shows the Utility proposal baselessly asserts zero value of solar and other DER to distribution savings. It incorporates an untested, poorly understood metering paradigm that is potentially hostile to residential consumers. It also offers an uncertain path forward, one unlikely to lead to a future where science and granular local utility data inform the Commission's determination of compensation for DERs and where all customers' rates are just and reasonable.

The EFC proposal, while also taking steps to reduce customer-generator financial compensation – including cuts to the distribution credit, a switch to monetary crediting, and the deduction of a host of non-bypassable charges from crediting – minimizes damage to the still-nascent New Hampshire DER market by avoiding arbitrary and sudden disruptions, and works toward a more rational long-term solution for all customers. The EFC proposal also establishes a specific and well-designed path to develop the data necessary to set more accurate rates to inform future investments. Measuring the two proposals by the mandates and objectives of HB 1116 and the still-applicable provisions of LEEPA reveals that the EFC proposal provides the only reasonable path forward.

These conclusions are also compelled by what may be the most surprising aspect of this case: the startling absence of data to prove – and lack of any real attempt to demonstrate – the utilities' claims. They would have the Commission believe that net metering offers financial compensation greater than necessary to provide a reasonable opportunity for customer-generators to invest in DER, and that it causes an unjust and unreasonable cost shift from net metering customers to other customers. Yet, they utterly failed to provide supporting evidence. Only the small utilities offered the marginal cost of service studies requested by the Commission in its Order of Notice. Time-stamped data on circuit and substation loadings was not available for most utility facilities, thwarting the achievement of the data granularity originally suggested by Commissioner Scott and then sought by many parties. Despite advocating "instantaneous netting," only one of the utilities has even a few meters capable of recording instantaneous use; meaning only a paltry 2,170 of some 600,000 total residential meters could do the job. No New Hampshire utility has any data about the impacts of "instantaneous netting" on small customers, much less the year of consumer consumption data that would be necessary to begin to inform consumers of the implications of such a regime for their investment choices. And despite asserting that net metering subsidizes DER, no utility attempted to use the solar rebate data publicly available at the Commission itself (size, total project cost, utility location and thus rates applicable) to substantiate that assertion.

This lack of data, and the utilities' failure to make a serious attempt to prove their claims, is not an issue of burden of proof. Rather, this is more glaringly an issue of proof itself. As the Consumer Advocate, a signatory to the Utility proposal, observed with characteristic candor, this proceeding has shown no cost shift to exist. The Office of Energy and Planning, while also endorsing the Utility proposal, likewise notes "the absence of comprehensive data upon which to craft" an alternative net metering tariff.[3] At the same time, the utilities' own testimony admits that DER can save distribution system costs, particularly where solar peaks are coincident with distribution system peaks – a coincidence that has been demonstrated using what data the utilities did provide.

Critically, virtually all of the data relevant to the cost of DER to all utility customers and to the benefits DER provides to ratepayers is in the control of the utilities themselves. The non-utility parties cannot create marginal cost of service studies without utility-generated data. These parties cannot measure circuit loads, even when the utilities will not. When, as here, utilities will not or cannot provide the data to properly set alternative net metering tariffs, the proper course is not, as the Utility coalition proposes, to slash out in the information darkness at the "… solar [that] is a good thing." (Tr. 3/28/17 PM at 77.) Rather, the proper course is to pursue the path of gradualism as proposed by Energy Future Coalition and endorsed at hearings by Staff witness Faryniarz, to design the studies and pilots necessary to obtain essential data with the specificity

[3] Office of Energy and Planning State of Support for the Utility/Consumer Settlement Agreement (March 22, 2017).

sought by Commissioner Bailey, and to create the bridge to the future sought by LEEPA, HB 1116, and the Commission.

At the same time, no party refuted the obvious implications of the principal exhibit offered by the Energy Future Coalition as part of its proposal, attached here as attachment "A," showing that solar penetration in New Hampshire lags that of every New England state but Maine. This chart, combined with the utility admissions that they are barely half way to their statutory net metering caps, strongly implies that net metering is not creating a crisis in New Hampshire. Moreover, the utilities were unable to prove lost revenues of any magnitude, providing mere estimates of lost *load* instead. Although neither final nor tested by the Commission, at their largest these estimates equal less than two-tenths of one percent of the revenues of Eversource and less than three-tenths of one percent of the revenues of Liberty or Unitil. And these so-called "lost revenue" calculations do not consider any benefits of DER.

The mandates and objectives established by the General Court remain clear. To the greatest extent possible in the available time period and with the information currently available, the mandates and objectives have been met and will be further advanced by the Energy Future Coalition proposal.

For these reasons, the Commission should issue an order approving or adopting the alternative tariff described by the Energy Future Coalition in its March 10, 2017 settlement proposal.

II. ARGUMENT

The Commission should make the following findings:

A. THE COMMISSION SHOULD RETAIN THE STATUTORY OPPORTUNITY TO MONTHLY NET METER PROJECTS UNDER 100 KW AND REJECT THE UTILITY PROPOSAL TO END NET METERING.

For customer-generators with less than 100 kilowatt ("kW") peak capacity ("small projects"), current law requires utilities to calculate a customer's bill by netting the total kilowatt-hours ("kWh") the customer imports from the grid over a billing period minus the total kWh it exports onto the grid over the same billing period. RSA 362-A:9, IV(a); RSA 362-A:1-a, III(a). Monthly net-metering is the common practice both in New England and nationwide. (Mueller, Tr. 3/27/17 AM at 56:10-13.)

The EFC proposal would retain monthly netting.[4] (Ex. 1 at 5-7.) The Utility proposal, in contrast, would convert all customer-generators, large and small, to a buy-sell arrangement in which there is no netting. (Ex. 5 at 10.) Instead, the utilities propose to pay customer-generators a reduced price for exports to the grid, as measured instantaneously on a bi-directional meter (also called "no-netting" or "instantaneous netting"). (*Id.*) The Commission should retain current law and reject the Utility no-netting proposal for the following reasons.

i. Instant Netting Sends Exactly the Wrong Price Signal.

The Utility proposal would incent net-metered customers to shift their load to peak use periods, which would be inefficient and costly to other ratepayers. (*See* RSA 362-A:9, XVI, (HB

[4] The EFC proposal would exempt certain non-bypassable charges from net metering, including the Stranded Cost Charge, System Benefit Charge, Storm Recovery Adjustment and Electricity Consumption Tax. (Ex. 1 at 4:14-21.)

1116), requiring consideration of rate effects on all customers.) From a rate design perspective, the price signal created by the Utility proposal is exactly backwards. As Mr. Mueller testified,

> [i]nsofar as solar in New England is still largely peak coincident, and so the value of solar energy generated on the rooftop of a residence has higher-than-average value to other ratepayers, it is a mistake in market signal to encourage generation to shift to that time. Collectively, we are better off if the solar customer has the incentive to export that energy during periods of high grid stress and high cost and use -- and not shift their loads to be coincident with that generation.

(Mueller, Tr. 3/27/17 AM at 67:10-20; *see also id.* at 57:15-58:5.)[5] Other witnesses concurred, noting that instant netting sends "a perverse, inappropriate price signal" (Below, Tr. 3/29/17 PM at 32:22) and that from a rate design perspective, the netting period should be commensurate with billing period, as would occur with the EFC monthly netting proposal (Faryniarz, Tr. 3/29/17 PM at 108:3-13).

Even Utility witness Ashley Brown conceded that rates should work to reduce, not raise peak loads. But then, incredibly, Brown tried to argue that instant netting is not a problem because solar does not generate at the system peak. (Brown, Tr. 3/28/17 AM at 61:5-10.) Mr. Brown's testimony is simply wrong. The history of the last decade proves the opposite—that solar is highly peak-coincident. In fact, ISO-NE has specifically adjusted its planning methodology to reduce peak load forecasts to reflect the consistent beneficial effect of behind-the-meter solar ("BTM PV") in reducing observed peaks. (Ex. 71 at 24, 32.)

For instance, as shown at hearing, the 2016 ISO-NE system peak occurred at in the hour between 2 pm and 3 pm on August 12th—at a time when BTM PV in the region was producing

[5] *See also* Rabago, Tr. 3/27/17 AM at 67-68; Phelps Tr. 3/27/17 AM at 68; Ex. 1 at 6:2-17.

717 MW, or 2.8% of peak loads. (Ex. 71 at 7).[6] Likewise, the 2015 peak occurred in the hour between 4 pm and 5 pm on July 20th. (Ex. 70 at 4.) As noted by Mr. Chernick, this is the norm for New England over the last dozen years (Chernick, Tr. 3/29/17 AM at 32:17-33:8; Chernick Dir. Test. at 10-11, Tables 1&2) and the consequent reduction in transmission and distribution system peaks due to BTM PV saves ratepayers tens and tens of millions of dollars annually. (Chernick, Tr. 3/29/17 AM at 33:9-35:12; Chernick Dir. Test. at 9-17.)

It would make no sense for the Commission to adopt an alternative tariff that undercuts these benefits by incenting net metered customers to shift load to peak periods, thereby reducing the clear, proven value BTM PV and other DERs provide to all ratepayers.

ii. The Utility Proposal Would Deny Customers the Data Needed to Evaluate Reasonable Opportunities to Invest In On-Site Renewable Generation.

Instantaneous netting should also be rejected because it would leave customers wholly in the dark as to the value proposition for a proposed investment. As Mr. Mueller explained,

> Customers have access to historical monthly energy consumption data. They do not have access to historical instantaneous energy use data in any meaningful way. And, so, you cannot explain to a customer the bill savings under an instantaneous netting regime with any degree of accuracy. And that creates a real problem for customers, in terms of their opportunity to make a reasonable choice about making this investment.

(Mueller, Tr. 3/27/17 AM at 75:7-17; *see also id.* at 55:18 – 57:2, 76:4-78:15, 101:17-22.)[7]

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[6] Behind-the-meter PV generation was going strong and made significant contributions to reducing load on all five of the highest peak net demand days in 2016. (Ex. 71 at 8.)

[7] *See also* Rabago, Tr. 3/27/17 AM at 67-68; Phelps Tr. 3/27/17 AM at 68; Chernick Tr. 3/29/17 AM at 40:17-42:7; Ex. 1 at 6:2-17.

This lack of data applies to all three utilities. Witnesses for each testified that their companies do not currently have instantaneous load data for their customers and that they lack the metering capacity to collect such data if and when any new tariff goes into effect.

- Liberty: none of its 40,254 residential meters are capable of recording instantaneous load or export data. (Tebbetts, Tr. 3/28/17 AM at 94:1-95:21.)
- Eversource: none of its 487,716 residential meters are capable of recording instantaneous load or export data. (Davis, Tr. 3/28/17 AM at 96:2 – 97:11.)
- Unitil: Just 2,170 of its 77,000 meters currently are programmed to read (unspecified) intervals shorter than a single billing period. (Meissner, Tr. 3/28/17 AM at 97:18 – 98:18.)

Further, the Utility coalition expressly disclaimed any intent to add in the future the metering capacity, communications system, data management or customer portals that would be necessary to make instantaneous load data available to customers (Tebbetts, Tr. 3/28/17 AM at 91:10-93:6; Labrecque, Tr. 3/28/17 AM at 100:20-101:5). Nor will the utilities add such capacity for the net metering export channel or for opt-in generation meters. (Davis, Tr. 3/28/17 AM at 106:7-107:4.)

This continuing lack of information would effectively eliminate reasonable opportunities to invest in DER under an instant netting regime. As Mr. Below testified, customers—even those who are particularly energy savvy—would be unlikely to invest in solar until they have the necessary data to determine how much of their load a project would offset, and thus the likely payback period on the investment. (Below, Tr. 3/29/17 PM at 80:8 – 84:5.)

In a related context, the utilities have endorsed the widely shared principle that an electric tariff should go into effect "only if metering information is available as an option to customers in a timely manner so that they can take action to reduce and manage their costs." (Ex. 72 at 15, GridMod Draft Final Report.) The same principle should apply here: it would be unreasonable to implement an alternative tariff unless and until customers have timely access to the data needed to take action to reduce and manage their costs. Until such a time, the netting period should match the billing period (the period for which customer-use data is available), and the billing period is currently monthly.

iii. The Cost of Instant Netting Will Eliminate Reasonable Opportunities to Invest.

The Utility coalition attempted to gloss over the problem of instant netting by presenting a pair of graphs that allegedly demonstrated, for a typical residential customer, that the price impact of the Utility proposal compared to the status quo was only a 14% decline in value. (Ex. 6, Attachment B at 9-13 and Ex. 67.) But on questioning, Eversource Witness Labrecque admitted that those graphs and financial computations in fact use hourly data (Ex. 73 at 2) and do not illustrate the effect of instant netting. (Labrecque, Tr. 3/28/17 AM at 118:17- 119:6). Indeed, neither the utilities nor any other party in the docket could provide a full year example of instant netting, because the data does not exist. (*See* Below, Tr. 3/29/17 PM at 36:4-21 (testifying that load and production graph tracked on a minute-by-minute basis look nothing like Ex. 67).)

The potential financial difference between monthly and instant netting is quite stark. When corrected using the worst-case scenario suggested at hearing by Mr. Epler (assuming no on-site use), the Utility proposal would reduce the savings to a customer-generator by 222%. (Bean, Tr. 3/27/17 PM at 167:17-24.). That may be a worst case but, as noted by Mr. Mueller, the combination of a wide cone of uncertainty and significantly lower compensation will negate reasonable opportunities in invest in DER:

> The solar project in New Hampshire, with the current status quo, is decidedly, you know, a marginal investment for most customers. And they have, at best, a marginal opportunity to make that investment with a reasonable return. So, if you layer on lower compensation, lower return, and greater uncertainty, you get to the point where no reasonable person is going to sign up for a project that has an equal chance of making money or not making money for them over time.

(Mueller, Tr. 3/27/17 AM at 138:9-20.) This combination will deny customer-generators the reasonable opportunity to invest in DER or receive fair compensation for such locally produced power. (See HB 1116.)

iv. Eversource and Unitil should use the same monthly netting methodology in New Hampshire that they use in other New England states.

The Utility instant netting proposal would also be a radical change from normal utility practices in New England and nationwide, even within utilities themselves. Eversource's distribution utilities in Massachusetts and Connecticut use monthly netting, as does Unitil in Massachusetts. (Phelps, Tr. 3/27/17 AM at 115.) The undisputed evidence was that if the same utility used wholly different net metering programs that varied state-by-state it would be both inefficient for the utility (and thus ratepayers) and highly confusing to customers. (Rabago, Tr. 3/27/17 AM at 118:15-24).

Arizona is the sole jurisdiction that is transitioning from net metering to instant netting (Phelps, Tr. 3/27/17 PM at 135:5-12); however, in Arizona, the utilities have long had advanced metering infrastructure in place and had at least a year's worth of instantaneous usage data for all customers. (Beach, Tr. 3/27/17 PM at 52:17-24.)

Rather, the trend in U.S. jurisdictions is to develop better data and infrastructure, including through use of pilots and marginal cost studies, to guide development of new tariffs that gradually shift the billing interval for both usage *and* export to shorter durations, such as hourly or critical peak periods. (*See, e.g.,* Bean, Tr. 3/27/17 PM at 136:16-21; Beach, Tr. 3/27/17 PM at 124:2-9 and 135:19-136:2.)

v. The Utility Proposal to End Net Metering for Customers Taking Competitive Supply Would Violate State Law.

The Utilities' instant netting proposal also includes a little-discussed provision applicable to small customer-generators taking service from a competitive supplier. Instead of receiving credits equal to the default service rate, the utilities propose that these customers would only receive the utility's wholesale avoided cost as calculated in Puc 903.02(i). (Ex. 5 at 4). The price difference between the two is generally very significant, roughly 50% of default supply. This structure would create an incentive for customer-generators to convert to default supply, perhaps creating a windfall for utilities but violating both the spirit and the letter of deregulation. *See, e.g.,* RSA 362-A:9, II. By law, only competitive suppliers may determine the terms, conditions, and prices under which they provide service and purchase net generation from customer-generators. *Id.* HB 1116 did not provide any discretion to change this provision. *Id.* at XVI. The Commission should reject the Utility proposal to change the terms for net customer-generators taking competitive supply.

vi. The Utility Proposal Raises Major Concerns Under PURPA and Could Have Severe Unintended Tax Consequences.

Finally, the Energy Future Coalition also urges great caution before the Commission considers adopting new, untested concepts that might substantially alter the current net metering paradigm. New Hampshire, through LEEPA, has long encouraged and relied upon net metering as a key element of its renewable energy policy. HB 1116 affirmed that reliance.

Nationally, however, opponents of solar and net metering have begun to push an agenda that includes new methodologies, such as buy-sell arrangements that do away with net metering. These arrangements could disqualify local customer-generators from the net metering exemption in the Public Utility Regulatory Policy Act ("PURPA"),[8] thus raising the risk of "federalizing" state DER policies and emboldening opponents of net metering to push for regulation of customer-generators under PURPA as wholesale generation. Preemption of New Hampshire's state policies to encourage renewable distributed generation and other DERs would be entirely contrary to the public interest as determined by the General Court through LEEPA and HB 1116.

A second potential problematic consequence of the Utility proposal to end net metering (and convert to instant, or no netting) could be to turn some portion of energy savings from residential net-metered projects into taxable income. For example, under the 80/20 rule, the portion of residential customer-generation that is exported onto the grid could become taxable income. (Below, Tr. 3/29/17 PM at 124:16 – 127:17; Ex. 66 at 6-8.) This could negate the homeowner's eligibility for the Residential Energy Credit under § 25D and might raise the specter that a significant portion of any exported generation would be taxable, further eroding the customer-generator's reasonable opportunity to invest in locally produced renewable power. (*Id.*)

B. THE COMMISSION SHOULD CREDIT DER FOR ITS DISTRIBUTION VALUE.

The value of DER to the distribution system is both an integral part of the benefit of DER to all utility customers, and an essential component of the compensation realized by net metering

[8] *See* Energy Policy Act of 2005, § 1251, 16 USC 2621 ("the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to local distribution facilities may be used to offset electric energy provided by the electric utility to the consumer during the billing period"); 106 FERC § 61,220, Order No. 2003-A, ¶ 744 (March 5, 2004)(exempting net metered retail electric customer-generators from FERC jurisdiction).

customers. The weight of evidence demonstrates that distribution value of DER is significant and, based on HB 1116's requirements, must be a portion of compensation given to those that are providing it. The Commission should find that the EFC proposal to value the distribution component in setting the monthly net excess credit is the only appropriate option given the weight of the evidence, the utilities' current deficiency in quality distribution system data and the unilateral nature of the regulated utilities control over the creation of such adequate data. Once sufficient information has been collected, the Commission will be in a better position to determine a more exact distribution value for DER systems.

The Utility coalition proposal to recognize zero value for distribution system benefits is unsupported in the record and contradicted by individual Utility coalition member testimony. Multiple witnesses for members of the Utility coalition recognized that there is some level of actual benefit to the distribution system and the customers served by it (*See, e.g.,* Ex. 16 at 6:2-11; Ex. 17 at 43:9-12). No Utility coalition witness, however, has attempted to quantify that value. EFC witness Thomas Beach provided testimony demonstrating that, based on available marginal cost of service studies, the value of DER to the distribution system could be expected to fall within the range of $16 to $29/MWh among the utilities. (Ex. 19 at 87, Appendix D-8, Table D-7).

The EFC distribution credit proposal strikes an appropriate balance by making real, but gradual, concessions in light of the current lack of data on the precise value of DER to the distribution system. There is no factual evidence of "zero" value (Ex. 65 at 44-45); there is evidence for both a two-step temporary reduction of 50% and a one-step reduction to 50% (Ex. 19, Table D-7.).

Moreover, only the EFC proposal is premised on the proactive creation and development of distribution system data that will make the determination of the distribution value a more accurate one. In contrast, the Utility coalition distribution credit proposal makes no provision to account for the lack of utility data and largely just echoes its member witnesses' early testimony that no credit is warranted since those witnesses were unable or unwilling to quantify a value. That utilities control the lines of sight into the operation of the grid suggests an intrinsic disincentive to increase visibility about how DER interacts positively with the distribution grid. Because the state of current information on the impact of DER on the distribution system is imperfect, the Commission should move cautiously and deliberately to adjust value of distribution credits in the immediate term and order the creation and analysis of adequate data to refine the true value of DG to the distribution system in the future.

In the absence of current essential data to provide an accurate representation of current and anticipated distribution benefits for DER systems, only the EFC proposal provides a moderate, incremental shift toward a future state where distribution values are more readily quantifiable and realizable. The stepwise reductions of distribution credit for monthly net excess generation by 25% in year one and 50% in year two provide a significant adjustment from the status quo that prepares the market for transition to a compensation method that more accurately reflects the actual distribution costs and benefits of DER. The Utility coalition's proposal represents an unfounded, extreme and austere departure from the status quo, particularly in light of the lack of evidence that the current distribution credit is not just and reasonable. The Commission should find that the EFC's distribution credit proposal best balances the interest in preserving a reasonable opportunity for customers to invest in DER, reducing costs to other customers immediately and rapidly creating a data-driven basis for determining an accurate price signal for distribution value in the future, after completion of the Value of Distributed Energy Resources ("VDER") study.

C. THE START DATE FOR ANY ALTERNATIVE TARIFF SHOULD PROVIDE 3-6 MONTHS LEAD TIME TO ALLOW THE DER MARKET, CUSTOMERS, AND UTILITIES TO ADAPT TO THE NEW RULES.

The start (and grandfathering) date for an alternative tariff should be no sooner than September 1, 2017. Ideally, the tariff would go into effect six months after an Order is issued (for example, on January 1, 2018), so as to provide the lead-time necessary for DER providers, customers, and utilities to adapt to the new rules.

As shown at hearing, anything earlier—and particularly the June 30th start date proposed by the utilities—is wholly unnecessary, unfair to customers and punitive for the DER market.

First, there is no emergency. No unjust or unreasonable cost shift has been demonstrated. All three utilities testified that they have plenty of room under the supplemental 50-megawatt net metering cap established by HB 1116. Eversource testified that roughly 50% of its small project allotment[9] remains open (Labrecque, Tr. 3/28/17 AM at 129:21-24); Unitil has just over 50% of its allotment open (Meissner, *id.* at 130:7-10); and Liberty has about 40% open. (Tebbetts, *id.* at 129:2-5).

Second, the utilities will not be ready to implement a tariff until the end of 2017, if not later. All three companies testified that their billing systems and/or meters are currently not capable of billing customers under either of the proposed new tariffs. Eversource will need 6 months to implement a new billing system, (Davis, Tr. 3/28/17 PM at 97:12-20); Unitil could not

[9] Most changes in both the EFC and Utility proposals apply to projects under 100 kW capacity.

say how long it needs (Meissner, *id.* at 98:13-20); and Liberty said it will need 3-6 months to update its billing system and to re-program meters (Tebbetts, *id.* at 95:1 – 97:9).

Third, the utilities conceded that their proposed start date was "just kind of a date we chose… there wasn't a real dire need for it to be June 30th." (*Id.* at 99:20-21.)

Fourth, the DER market also needs lead-time to adapt to any new rules. Depending upon the scale and impact of the changes, this could range from a big task to a fundamental re-thinking of their business model and product lines. For both proposals, at a minimum, solar installation companies will need to obtain additional data from customers (which, for the Utility proposal does not exist), revise their modeling programs, reconfigure their design and sales processes, produce and publish all new sales materials, re-train sales staff, and re-educate customers. (Mueller, Tr. 3/27/17 AM at 40:5-22). This cannot be done in a month; indeed, it may take much longer than the 3 months proposed by EFC. (*Id.*)

Fifth, rushing the start date would be unfair to customers. The solar sales process is about 4-7 months long, with several months from first contact with a customer to a purchasing decision. (*Id.*; *see also* Mueller Tr. 3/27/17 PM at 122:20 - 123:7). Changing the tariff on a mere 30-day notice as proposed by the utilities would disrupt this process, force installers to re-design and re-bid many projects and fundamentally disrupt customer expectations. This is both unwise and unfair when the utilities would not even start billing the new program until next winter.

D. THE COMMISSION SHOULD ADOPT THE DATA COLLECTION AND STUDY RECOMMENDATIONS AND THE FOUR PILOT STUDIES PROPOSED IN THE EFC PROPOSAL.

The additional data and experience from pilot studies are critically important for refining price signals and developing final alternative net metering tariffs. Recognizing this, the Energy

Future Coalition has proposed a series of data collection efforts, rate design pilots, and an independent VDER study (Ex. 2 at 4) to inform Phase 2 programs and create a smarter, lower cost grid (Bean, Tr. 3/27/17 AM at 45:2-6). Both the EFC and Utility proposals recommend the creation of working groups to develop data collection, studies and pilot study plans for Commission approval. Through its Order in this case, the Commission can provide guidelines so that the working groups can focus on specific aspects and timelines, rather than overarching topics that may lead to delaying the efforts. Such guidelines can include the timing and length of pilots, collection and dissemination of data and program updates, estimates of system upgrades required to enable the pilot (such as billing and metering), and accounting of costs to administer the programs.

i. EFC data collection and study recommendations

The Energy Future Coalition proposes a Commission-sponsored, independent VDER study to inform the crediting value in Phase 2. To implement Phase 2 by January 1, 2021, the EFC settlement proposes that the VDER study be complete by early 2020, and, following an Order in this case, that a collaborative working group develop data requirements and methodologies for Commission approval (Ex. 1 at 15:4:8). The Commission can define the parameters and methodology of the VDER study in the Order in this case so that the working group does not reach an impasse. Considerations to include in an Order include study scope, time horizon, data collection efforts, and methodology. Commissioner Bailey has appropriately sough specificity in this area.

The Energy Future Coalition recommends the Commission order define study scope to set expectations and assure the right data can be collected and monitored in the lead up to the analysis. (Rabago, Tr. 3/27/17 PM at 48: 3-6; and Bean Tr. 3/27/17 PM at 48:7-10). An analysis should look at costs and benefits of VDER over the long-run, such as the economic life of DERs (Beach, Tr. 3/27/17 PM at 48:13-16 and 117:5-7). Data should include loadings at the substation and circuit levels, and the utilities' marginal distribution costs. (Beach, Tr. 3/27/17 PM at 140:14-24). The study should evaluate the costs and benefits from different perspectives, such as for non-participating customers through a Rate Impact Measure test, and all ratepayers through the Total Resource Cost test (Beach, Tr. 3/27/17 PM at 142:12-20).

ii. Low-income pilot

The EFC and Utility proposals agree that a pilot for increasing the access of DER to low- and moderate-income customers is warranted. The Energy Future Coalition recommends that each utility host a pilot of at least 100 low to moderate income customers. (Ex. 1 at 15:19-24). The Utility proposal recommends a pilot for non-host low and moderate income to participate in net metering through monetary on-bill credits (Ex. 6 at 6) and that the program be reviewed by a task force (Ex. 6 at 8).

iii. Time-of-use pilot

A time-of-use ("TOU") pilot was included in both the EFC and Utility proposals, with differences in pilot design. The Energy Future Coalition recommends that the Commission adopt specific parameters and design for the pilot. Experiences from other states, including Xcel Energy in Colorado, can help serve as a guide to frame the study's development and objectives (Ex. 46 at 8:1-7). In that case, the utility worked with stakeholders and filed an extensive pilot study and evaluation plan, which has been filed as Exhibit 47 in this case. Exhibit 47 can be useful for developing a successful pilot program here.

The current optional TOU rates provided by Eversource and Liberty Utilities do not provide customers with actionable price signals because their 13-hour peak windows are far too long a time to give customers a reasonable opportunity to shift demand. (Bean, Tr. 3/27/17 PM at 38:1-15). The Coalition recommends that the TOU rate recover the underlying energy and delivery revenue requirements and send signals about high demand periods (Ex. 1 at 16:6-9). The rate should be designed to reflect the hours in which demand is typically within 5% of the system peak (Bean, Tr. 3/27/17 PM at 38:15-18), which would be 11 A.M. – 6 P.M for Liberty Utilities (Ex. 21 at 13:17-18), 12 P.M – 7 P.M. for Eversource (Ex. 21 at 14:5-6), and 12 P.M. to 6 P.M. for Unitil (Ex. 21 at 14:19-21).

Another key difference between the EFC's TOU pilot proposal and the Utility proposal is that the Utility proposal seeks to limit the TOU rate to net metered customers. (Ex. 6 at 6). Given the growing variety of DER that customers can adopt—including solar, but also storage, energy efficiency, electric vehicles and demand response—it is important for pilots to send more precise price signals to all customers. The Coalition recommends that the pilot be open to all customers (Bean, Tr. 3/27/17 AM at 45:1-23) and that a more actionable TOU rate be made available to all customers as an optional rate in the future. (Bean, Tr. 3/27/17 PM at 120:2-8). While solar customers can be a central part of such a pilot, others should not be excluded.

iv. Smart Energy Home Pilot

The Energy Future Coalition recommends a "Smart Energy Home" pilot which would test more complex rate structures such as real-time pricing or combinations of TOU rates with critical peak pricing or demand charges. These types of rates send signals to customers to reduce demand or increase production during a specific event or period, such as a critical peak hours, thus enabling customers interested in more active management of their demand to provide additional value to the grid and other ratepayers. Testing such designs through a pilot can provide experience with the more complex rate designs and potentially lead to optional rates in the future that send customers more dynamic and precise price signals (Bean, Tr. 3/27/17 PM at 120:2-8). The design of this pilot incorporates recommendations from a variety of parties, including the City of Lebanon's real-time pricing pilot (Ex. 25 at 7:183-197), demand charge proposals from Unitil (Ex. 8 at 45:4-12) and Eversource (Ex. 15 at 4:24 – 5:2), and consideration of a storage pilot from the Staff (Ex. 65 at 134:14-17).

v. Non-wires alternative pilot

The Coalition proposes a pilot to test the concept of non-wires alternatives by deploying DER to replace or defer traditional transmission and distribution investments. (Ex. 1 at 17:1-2). The three utilities have minimal experience evaluating and testing non-wires alternatives in their distribution system planning processes (Ex. 21 at 8:12 – 9:9). A non-wires alternative pilot will provide utilities with valuable experience and help modernize their system planning process to ensure that system costs are minimized. (Ex. 1 at 17:2-4). The pilot can advance the objectives of HB 1116 and provide critical information for the transition to Phase 2. For example, the pilot can provide critical locational data about the positive impact DERs can have on the distribution system, and provide a better understanding of the short- and long-run marginal distribution and transmission capacity costs (Ex. 1 at 17:6-16). Staff also supports the adoption of locational siting pilot programs, stating that the pilot "would allow all parties to gain better visibility into the utility distribution systems, better understand the ability of DG resources to positively impact the distribution system, enable the utility capital investment process to properly consider DG resources as non-wires alternatives, and be useful for the collection of further data on all these matters." (Ex. 65 at 123:9-17).

Non-wires alternative examples are proving highly beneficial elsewhere. A prominent example is the Brooklyn-Queens Demand Management Program administered by Con Edison in

New York. Con Edison proposed procuring non-wires alternatives and traditional grid investments for $200 million in order to defer a $1 billion traditional grid investment for several years. (Ex. 21 at 11:11-13). Con Edison produced guidelines for participating in the program (available at Ex. 21 at 52-69). That document can serve as a framework in this docket. The "GridSolar Boothbay Sub-region Smart Reliability Pilot" in Maine also provides a good example how pilots can be structured and the benefits they can yield—the study found roughly $12.5 million in short-term or direct savings due to the relatively small pilot. (Hawes, Tr. 3-29-17 AM at 27:13-20).

vi. The Utility pilots and data collection proposals should be rejected

While the Coalition agrees in principle with the Utility proposal for low income and TOU pilots, the Coalition recommends that the Commission reject the Utility locational value study, VDER study methodology, and recommendation for studying annual load data of net metered customers, as these studies are not designed to lead in useful directions.

The locational value study is described as being similar to the Nexant study performed for Central Hudson Gas & Electric in New York. (Ex. 5 at 8). The stated objectives of the Nexant study include analyzing load patterns, excess capacity, load growth rates, the magnitude of expected local infrastructure investments, developing location specific forecasts, quantifying the probability for infrastructure upgrades, calculating avoided delivery costs, and identifying beneficial locations for DERs. A non-wires alternative pilot and independent VDER study will achieve the essential objectives of calculating avoided delivery costs and identifying locational benefits of DERs. The other components of the Nexant study should not be piloted, and instead should be standard practices in any utility planning process.

The Utility proposal for studying annual consumption patterns should be similarly rejected. Annual consumption data does not provide insights for developing more precise price signals or valuations. (Bean, Tr. 3/27/17 PM at 111:9-16.) While such information can be useful for calculating lost revenues (Epsen, Tr. 3/27/17 PM at 12:2-4), the monthly consumption data for net metered and non-net metered customers is seemingly available at present, thus making a dedicated study of the information potentially redundant and administratively burdensome. In contrast to the Utility proposal, including a pilot program to credit large customer-generators for value they provide in reducing transmission costs (Exh. 6 at 6), the EFC proposal would make this transmission credit available to all large customer-generators on an opt-in basis (Exh. 1 at 13:8-12). The record demonstrates, and the Utility proposal even acknowledges (Exh. 6 at 4), that net metering facilities, regardless of their size, provide transmission cost savings for all customers. There is no reason to deny these benefits to all large customer-generators (who additionally pay demand charges); an opt-in program should be available to them. A pilot program would not be generally available to large customer-generators, nor would it promote valuable cost savings for all customers.

E. THE COMMISSION SHOULD DEFINE A CLEAR TRAJECTORY TO THE FUTURE, AS PROPOSED BY THE EFC.

The principles of gradualism and the values of HB 1116 and other applicable law as expressed by the General Court and by the Commission also favor defining a clear trajectory between the present and the future.

The presence—or lack—of a defined trajectory between the present and the future significantly affects whether electric customers have reasonable opportunities to invest in and interconnect customer-generator facilities and receive fair compensation for such locally produced power as intended by HB 1116. (Tr. 3/27/17 AM at 38:8-11: "there is real risk that significant changes for the worse for could foreclose that reasonable opportunity to invest in the future.") Such a defined trajectory is a hallmark of gradualism. Staff witness Faryniarz testified: "One of the key principles of the Staff review and my review was the ratemaking principle of gradualism. And I do believe one proposal has more in the way of merit on that score… That would be the Energy Future Coalition proposal." (Tr. 3/29/17 PM at 107:9-16.)

The EFC proposal defines a trajectory that supports reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation for such locally produced power—a "comprehensive roadmap for the state going forward" which "seeks to collect more granular data and experience with alternative programs in order to transition to a program of more precise signals to all customers and for distributed energy resources." (Tr. 3/27/17 AM at 32:3-8.) It represents a "phased and careful but deliberate transition to an alternative net metering tariff, designed to prevent customer confusion or rate shock, that will maintain customer choice and clean energy jobs here in the state, require data collection and pilots to inform future phases, and keep a fair balance for DG customers and other ratepayers, all per the direction of House Bill 1116." (Tr. 3/27/17 AM at 39:5-14.)

The Energy Future Coalition proposes "two phases: Near term changes to lower costs and immediate studies managed by the Commission to gather essential data with all deliberate speed, and then Phase 2, in which the Commission uses that data to create better price signals to inform consumption decisions and maximize the value of DER investments to the grid." (Tr. 3/27/17 AM at 36:5-12.) The proposal envisions "a transition to Phase 2 based on the completion of the studies and the collection of <u>data we wish we would have had in this proceeding</u>." (Tr. 3/27/17 AM at 48:11-14 (emphasis added).) This is consistent with Staff's recognition "that significant additional data collection from more advanced metering data on T&D system benefits and costs of DG integration, potential pilot programs and studies, such as we and others have recommended, would all help to better develop a record for establishing a more durable NEM tariff. However, a bridge is needed to get to that point and allow those pilots and studies to bear fruit. Our recommendations for such studies were intended to inform future Commission decisions on the construct of future DG rate design to ensure proper price signals and adherence to ratemaking principles." (Tr. 3/29/17 PM at 88:24-89:13.)

The EFC proposal is just such a bridge. Both proposals propose pilot studies and data collection; the critical differences are the number, depth and useful direction of the pilot studies. (Tr. 3/27/17 AM at 44:15-18.) Unlike the Utility proposal, the EFC proposal has a clear destination – a Value of Distributed Energy Resource-based tariff: a rate structure that will allow customers to interact with the electric grid in a way that lowers costs for all ratepayers and that enables investments in a variety of new technologies. (Tr. 3/27/17 AM at 39:15-22.) The destination of the studies proposed by the Utilities is at best unclear. This is a critical shortcoming of the Utility proposal.

The approach taken in New York to transition to value-based rates is similar – the Commission can take advantage of lessons learned there and elsewhere. According to the New York Public Service Commission's recent *Order On Net Energy Metering Transition, Phase One Of Value Of Distributed Energy Resources, And Related Matters* (Ex. 1 at 11:19-12-5), residential mass market customers will remain subject to retail net metering until January 2020, when they will transition to VDER. In the meantime, community net metering and larger customers will be compensated for exports using a VDER approach. The Order lays out the methodology to be used to calculate this rate. The New York Public Service Commission's value stack includes energy value, capacity value, demand reduction value and environmental value. In contrast, the Coalition only asks the Commission to determine a value for avoided distribution costs in Phase 2. The New York Public Service Commission has also recommended that utilities develop more granular locational prices and values to their distribution systems from DER additions and to facilitate third-party contributions to determination of values.

To maximize bill savings and other long-term benefits, the Energy Future Coalition proposes to move toward a new tariff in Phase 2 that both reflects the value of DER and incorporates the data and experience developed from the pilots during Phase 1. (Tr. 3/29/17 AM, at 24:11-16.)

Unlike the Utility proposal, the EFC proposal "places great urgency on completing pilots and then ensuring the results are used to inform Phase 2 programs. The rate design and non-wires alternative pilots we've proposed will allow for more targeted DER deployments and more precise price signals to create a smarter, lower cost grid. The programs will provide valuable experience and fulfill [HB 1116's] objectives of promoting resource diversity, independence, reliability, efficiency, regulatory predictability, a fair allocation of the costs and benefits, and a modern and flexible electric grid that provides benefits to all ratepayers." (Tr. 3/27/17 AM, at 44:24-45:14.) Indeed, the pilots and the transition to a value-based Phase 2 following an independent Value of DER study are critical parts of the EFC proposal. The business value of the resulting increases in long-term certainty and predictability is the business justification for the agreement in the EFC proposal to reduce the distribution component in the near-term. (Tr. 3/27/17 AM at 44:18-23.) It is also the policy justification. Without that overall roadmap, the EFC parties would not have reached the same agreement.

In contrast, the Utility proposal would not collect the proper data to inform such a Phase 2, nor would it define the contours of a Phase 2. The extreme devaluation of a "zero" distribution credit would have no relation to any assured accurate determination of the value of DER to consumers. The Utility coalition study of the Value of Distributed Energy Resources, for example, would not allow the consideration of long-term projections or forecasts. (Tr. 3/27/17 AM at 61:7-10.) Utility distribution and transmission investment is planned on a long-term basis that accounts for useful lives of many decades; the DER that can avoid such investments should be evaluated on the same timetable of its own useful life. (Tr. 3/27/17 AM at 61:10-15.)

Finally, there is little or no purpose to spending money and time on studies that have no target and purpose – i.e. their consideration in the development of an accurate, value-based rate for net metered customers, and of other Phase 2 customer options to maximize the grid value and increase bill savings. As noted in hearings, "the Utilities do not propose any time frame for transitioning to value-based compensation or trajectory for introducing meaningful price signals designed to lower bills. And regarding the value of DER study that they do include, they propose that the Commission be limited to considering realtime market prices, distribution system needs and near term marginal costs and that the Commission be prohibited from considering any longer term cost in setting rates for generation resources that will produce decades of benefits." (Tr. 3/29/17 AM at 44:22-45:10.) This borders on the senseless. A rational forward-looking roadmap must include a target timeframe and the future adoption of value-based rates.

Similarly, there is no Utility commitment to periodic updates of their pilot studies, or procedures to require the use of Value of DER studies or various pilots to inform future tariffs. The opportunity to enhance accuracy and avoid waste is lost. (Tr. 3/27/17 AM at 61:21-62:5.)

F. THE COMMISSION SHOULD ADOPT THE EFC TREATMENT OF NON-BYPASSABLE CHARGES.

An important component of the EFC proposal is the treatment of non-bypassable charges on the customer-generator's bill. These charges include the System Benefits Charge, the Electricity Consumption Tax, the Storm Recovery Adjustment and the Stranded Cost Recovery Charge. Under EFC's proposal, customer-generators would be billed on imported kWh and would not receive credit for exported kWh. To move toward a more granular, value-based rate system, the Energy Future Coalition recognizes that non-bypassable charges often reflect other state policy goals (such as revenue for the state's General Fund or low income customer bill assistance) that are not directly impacted by the amount of DER capacity. Likewise, the stranded cost recovery charge reflects historical costs incurred by a public utility. The current and future benefits of net-metered DER are not necessarily able to help alleviate the burdens of past investment decisions. The excluded non-bypassable charges should be well-defined in the final order, and not open to future and unknown adjustments as contained in the Utility proposal.[10] Leaving the door open to unspecified non-bypassable charges would create uncertainty in the future rate at the point of investment for the customer, uncertainty that is beyond the routine

[10] For example, future major changes in the Stranded Cost Recovery Charge should be reviewed for inclusion or exclusion in net metering.

fluctuations in other components of the rates such as summer and winter default energy service rate adjustments.

III. CONCLUSION

The Energy Future Coalition urges the Commission to issue an order adopting or enabling the alternative tariff described by the Energy Future Coalition in its March 10, 2017, settlement proposal. Only the EFC proposal satisfies the mandates and objectives in HB 1116 and in LEEPA. In light of these statutes and based on the evidence, the Commission should find that the proposal of the Energy Future Coalition reduces financial compensation to customer-generators for their locally produced renewable power materially while minimizing unnecessary and unjustified disruptions to the still-nascent New Hampshire DER market and further recommends a specific, well-designed path to availability of the data necessary for and creation of accurate net metering rates. When compared to the Utility proposal in this same statutory light, the Energy Future Coalition proposal emerges as clearly in the public interest.

Respectfully Submitted,

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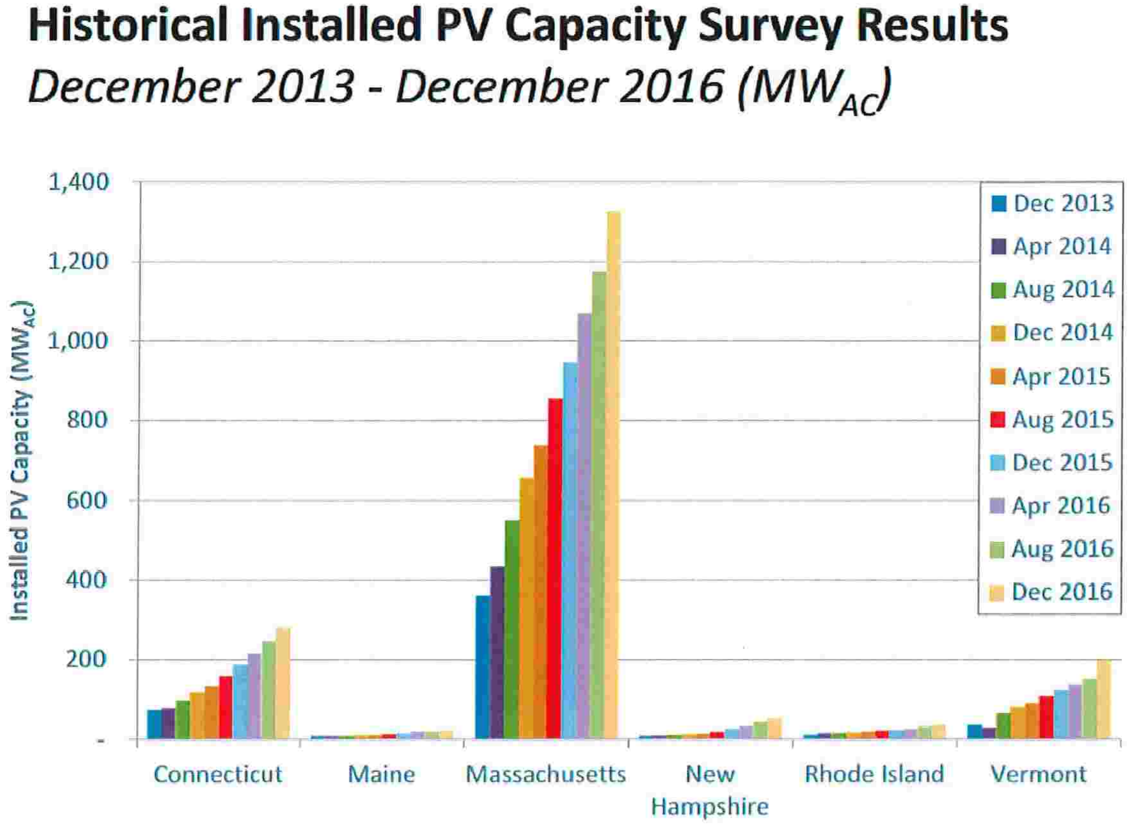

Figure 1 – Historical Installed Distributed Solar Capacity. Source: Victoria Rojo. February 28, 2017. "December 2016 Distributed Generation Survey Results." ISO-NE Distributed Generation Forecast Working Group.