EXHIBIT
#27
DE 16-576

NEW ENGLAND RATEPAYERS ASSOCIATION

DIRECT TESTIMONY OF

Michael Harrington

New Hampshire Public Utilities Commission

Docket Number DE 16-576

Q. Please state your name and address.

A. My name is Michael Harrington and I live at 82 Garland Road in Strafford NH.

Q. Please provide your education and business background

A. I have a Bachelor of Sciences degree in Nuclear Engineering from UMASS-Lowell. I spent 25 years working in the power generation field. I held various engineering and management positions at the Seabrook Nuclear Power Plant. In 2000 I was elected to the New Hampshire House of Representatives and served four years on the Science, Technology and Energy Committee. Starting in 2004, I spent nine years at the New Public Utilities Commission serving two non-concurrent terms as a Commissioner and as the Senior Regional Policy Advisor. During this time, I was highly involved in the New Hampshire and New England electric markets and also served as New Hampshire's Manager for the NESCO. My presence in this docket is as an advisory board member to the New England Ratepayers Association.

Q. What is the purpose of your testimony?

A. To provide a framework for a new net metering tariff as well as to dispel some common myths regarding distributed generation in general and rooftop solar in particular.

Q. Please comment on the current net metering tariff?

A. The current net metering tariff in New Hampshire represents an ill-conceived and irresponsible cost shift from non-solar customers to those who can afford to install solar generation. Instead of the current arbitrary tariff which was established in part due to the simple form of metering at the premises, the Commission should institute a tariff that properly reflects the value of the electricity generated, when it is generated and where it is generated. This pricing structure will provide benefits to the solar generators when they are producing power when the regional grid needs it most, while sending price signals to those same generators if they are producing electricity when the grid is not short of power. Any other form of tariff will only be a distortion of pricing, create a cost shift burden on some portion of the ratepayer base, and will create the wrong types of incentives to participants.

Q. Does distributed generation, particularly solar generation provide capacity value to the grid?

A. Solar advocates have argued that distributed solar generators are providing substantial benefits to the grid. One of the major elements of compensation that the solar companies attempt to put into net metering tariffs is a large "capacity" benefit. Depending on the study, this benefit request can be as large as $50/MWh ($0.05/Kwh)[i]

Given the form of intermittent power produced from solar, and the fact that the capacity market payments are made to those generators who can produce electricity at the times when the grid needs it most (and not necessarily the times when those producers can/will produce electricity), it makes little sense to provide a capacity benefit to solar generators. Many studies have shown that in fact, solar generators are not peak producing coincident with peak load.[ii] Typical peak loads in New England and New Hampshire occur in the late afternoon hours in the summer and in the early evening in the winter. Unfortunately, solar power tends to peak a little after noon, when the ISO-NE grid does not typically face capacity constraints. In addition, maximum solar generation occurs in the May/June timeframe which typically are low demand months in New England. On this basis alone, a capacity benefit in the net metering tariff makes little sense to consider.

Solar advocates will argue that even if solar is not peak coincident, the ability of solar generators to lower demand during the day provides some benefit to the grid, but even that argument doesn't provide a substantial case to justify inclusion of some compensation through net metering. Capacity payments are made to ensure the stability of the grid at times of stress. It is a system of compensation that flows to generators (from the users through their electric bills) that can ensure that electricity will be available in times of high demand. In fact, the ISO-NE has included a future "pay for performance" mechanism to ensure that those generators who receive capacity compensation deliver at times of need or face financial penalties. If solar generation is providing a capacity benefit, then solar generators, either directly or through an aggregator, can and should bid into the capacity market directly and receive the appropriate market-derived compensation. The intermittency of solar makes this difficult since any and every solar generator has no ability to ensure that they will be able to generate electricity at the most critical times when the system needs power.

When it comes to the capacity market, the most recent trend in New England's Forward Capacity Market is very instructive as to the net benefit/cost of intermittent resources. Over the past decade, New England has been incorporating more and more renewable resources into the regional grid. Due to external policies driven for political reasons, these resources receive numerous taxpayer and ratepayer funded subsidies and benefits through mandates, renewable energy credits (RECs) and production/investment tax credits. The result of this out-of-market support for these generators has allowed them to bid into the wholesale energy market at “below market” rates distorting the resulting Locational Marginal Price. All generators who don’t benefit from these “out-of-market” subsidies are faced with reduced revenues in the wholesale market for their power. Recently, the ISO-NE has started to allow negative prices (as low as -$150/MWHR) to be bid into the wholesale market, which results in only subsidized generators being able to economically produce power at those times of negative prices. The consequence of this type of wholesale power structure is that the New England region is now seeing many large, energy market dependent generators who could provide capacity being decommissioned. The economics of the wholesale market, driven by in some part by the intermittent generators like solar which are supported by non-market compensation, is removing some generators who could bid into the capacity markets and lower overall capacity costs to ratepayers. Many generators who have left the market have indicated that the artificial taxpayer and ratepayer subsidized decline in wholesale energy pricing as a factor (e.g. Vermont Yankee) in their decision.[iii] This results in intermittent DG suppliers costing ratepayers through the distortions they are causing to the energy and capacity markets. Quantification of this shift in cost is difficult to calculate, but it is clear from the recent increases in annual capacity payments from approximately $1 billion a year (for New England) to $3-4 billion a year, that this distortion by subsidized power like solar is creating a net capacity <u>cost</u> to non-solar ratepayers. Despite this limitation, the PUC should take into consideration the likelihood of this element of the tariff as a net COST and not a net benefit as the DG advocates argue.

Q. Proponents of net metered distributed generation systems often cite increased grid reliability as a reason to continue to support retail net energy metering policies. Do you agree with these sentiments?

A. No I do not. For example, the power inverters that are required for distributed energy systems are designed with a safety mechanism that turns them off in the event of an outage on the distribution system. This safety mechanism would (rightly) prevent a DG system from feeding power to the distribution system during an outage—if this safety measure were not in place utility lineman would be in danger of encountering live voltage while repairing a downed line. The end result is that only the DG host is receiving power and benefits from their DG system during an outage.

More importantly, the greater integration of solar DG negatively impacts grid stability on a much broader scale than the enhancements it theoretically makes on a local level. The very real implications of a more extreme duck curve (Figure 1) means that the region as a whole, and ISO-NE in particular, must manage a much more volatile and less predictable load environment throughout a particular day. Instead of a steady and regular ramp in the morning hours, a peak in the late afternoon and a steady ramp down at night, renewables in general and solar DG in particular, creates a morning demand peak, a deep afternoon valley, and then an even steeper

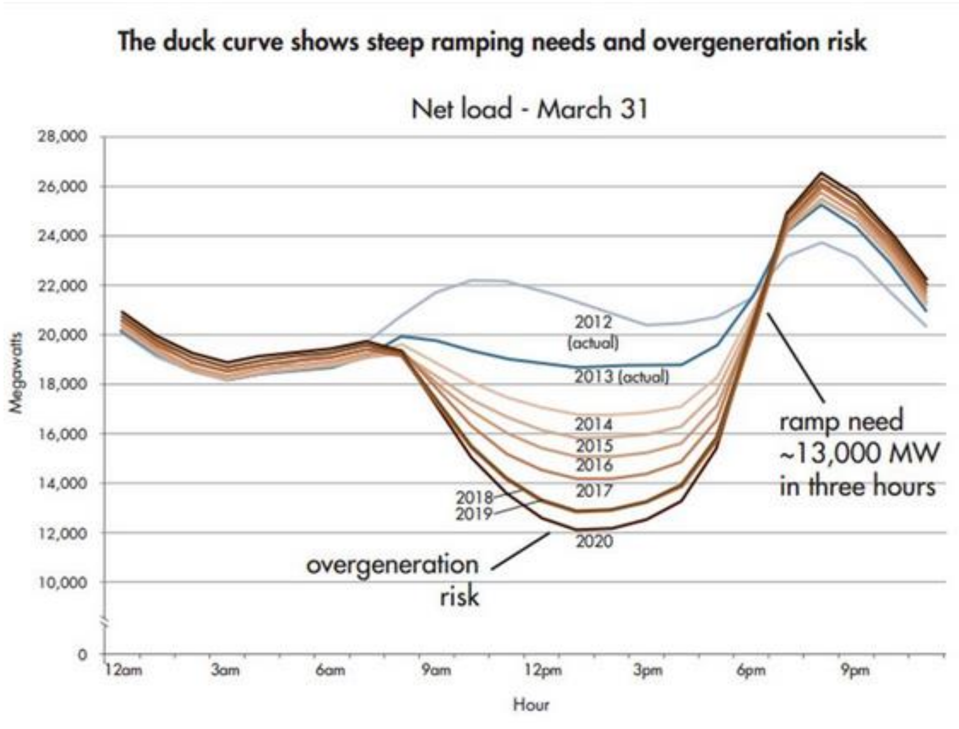

Figure 1

late afternoon peak. This requires far more grid management activity and a much larger coordination with fast start units, which makes the risk of grid destabilization greater, not less.

Beyond this macro concern for grid stability, the fact that an unforecasted overcast condition can occur means that large quantities of solar generation can flip from being electricity suppliers to electricity demand. If this were to occur at a peak coincident time in a high demand zone of New England, there could be serious problems trying to identify, start and then shut down large amounts of generation to compensate for the intermittency and vulnerability of solar DG generation.

Q. Could you please briefly explain Demand Reduction Induced Price Effects (DRIPE) and its relationship to Distributed Generation?

A. DRIPE is essentially savings that consumers may see from a reduction in electricity demand, both capacity and energy. However, it is extremely difficult to quantify any purported benefits that DG, especially rooftop solar which is not peak coincident, may have. DRIPE is often cited as a result of increased energy efficiency investments, but retail net energy metering actually distorts energy efficiency in that full compensation for “banked” generating credits fails to incent the DG homeowner from investing or partaking in energy efficiency measures. Any DRIPE “benefits” MUST not only be quantifiable, but if included in a net metering tariff should also be proven to be the ‘least-cost” method for achieving demand reduction savings. Including DRIPE in a net metering tariff is akin to providing additional compensation (beyond the electricity savings) to a homeowner that makes the personal financial decision to unplug his/her second refrigerator. The PUC will be going down a dangerous and very expensive road for ratepayers if it chooses to subsidize this type of activity through a formal compensation structure. This is especially problematic as the demand reduction from solar DG is not necessarily coincident with peak load and therefore is likely to be providing marginal benefits at best. In addition, demand response and energy efficiency(EE) compensation are currently available through existing ISO market mechanisms. The FERC has recently confirmed ISO-NE’ s compensation method for Demand Response and EE is allowed to bid into the New England Forward Capacity Market. If solar advocates believe they should be compensated for this type of benefit, then they should use the existing structures and not hide this compensation in a net metering tariff.

Q. Does increased DG penetration provide any specific challenges to utilities and or New England's ISO?

A. Yes is does. Here are a few:

ISO grid management

Related to the localized load forecasting costs, ISO-NE has frequently indicated that they are being challenged more and more by the incorporation of intermittent generation as it is added to the New England grid.[iv] While the ISO-NE has indicated some of the specific changes they have had to make to their practices, the exact cost of this grid management process is ultimately borne by the ratepayers of the region. These costs could include increased weather forecasting services, more personnel devoted to real time or near real time wind and solar projections, greater oversight of the substantial drops/surges in intermittent generation by wind and solar, and ultimately the increased costs associated with immediate dispatch to ensure grid stability in times of the substantial drops/surges of electrical generation from wind and solar. ISO-NE has not publically provided any data on these incremental costs, but they are solely due to intermittent power supplies. As such, the net metering tariff should consider and incorporate to the extent that ISO-NE can quantify these elements for the PUC.

Grid Destabilization Costs

The incorporation of distributed generation creates a new set of challenges for the operation of the grid. The transmission and distribution infrastructure were initially designed and maintained for uni-directional power flow. Power was generated at central locations and moved across the transmission and distribution lines to the end users. For the most part, all the electricity “ran downhill”. In an environment with distributed generation at the local loop, the need for bi-directional electricity flow becomes greater. In certain circumstances, a local loop with a large amount of solar power generation located on it will need to “export” any additional electricity that cannot be consumed on the local loop. Ratepayers eventually have to cover the cost of this incremental investment in the distribution system to manage this type of problem. In addition to requiring a change in the equipment at the local substation that allows bi-directional flow, it also creates a more dynamic electrical flow that requires a higher level of management to prevent events that can destabilize the local or regional grid. This problem is not theoretical, and in fact has become a primary reason for the State of Hawaii to impose higher tariffs/fees on solar generation.[v]

In addition to this type of local loop problem, the daily production curve of solar generation creates greater challenges to maintaining the stability of the grid. Typically, solar generation slowly ramps up in the morning, peaks shortly after noon, and then quickly drops in the late afternoon or early evening[vi]. Of course, this pattern is effected by the time of year and the local weather conditions, but even considering the average pattern, it creates the potential to cause problems managing the transmission and distribution network. For a given region (in this case New England) increasing penetration of solar generation requires other forms of generation to ramp down as solar ramps up in the morning. This pattern then must be reversed in the late afternoon as solar pares down. But since peak demand in New England typically occurs in late afternoon hours both in winter and in summer (the two peak demand periods of the year) and is not coincident with peak solar generation, solar is ramping down just as demand is also ramping up. Many states and regional grid managers increasingly face the problems associated with distributed generation. This creates a far steeper ramp than if distributed solar generation did not exist and requires the ISO to more adeptly manage the transition from solar to other generation over a short period of time. Since most traditional baseload generation does not ramp that quickly, smaller and more expensive peaker units must be dispatched to manage this rapid increase in net demand (net demand in this case defined as the loss of solar generation PLUS the increase in typical demand from non-solar users PLUS the increase in demand from solar users as they no longer have their distributed generation systems producing electricity). The result is a greater risk of a local or regional disruption in power and higher costs as the ISO attempts to manage these large swings in generation and demand.

This incremental cost to manage a less stable grid is what can be referred to as a grid destabilization cost (GDC). It includes the costs to manage a local loop problem when large amounts of distributed generation are installed on a particular local loop, requiring both additional equipment and better management practices by the grid managers. In addition, it is the costs incurred by ISO to manage the regional grid in an environment with larger and more rapid ramp up/down due to the installation of distributed generation with its daily fluctuations.

Elements of the Grid Destabilization Cost are quantifiable, but require substantial input from ISO-NE as to the specific values. What can be irrefutable is that these costs are greater than zero and are not theoretical.

Q. It is often argued that support for retail net metering creates local jobs and economic growth. Please comment on this assumption.

A. Any study claiming economic benefits of DG must not simply look at the number of jobs in the industry; but also, look thoroughly at the impact of money being removed from the economy due by distributed generation policies, ratepayer and taxpayer subsidies, avoided property taxes and job losses imposed on other participants in the energy sector due to public policies that favor renewable energy. For example, the negative economic impact of the Vermont Yankee nuclear plant closure—which was closed for, among other reasons, artificially depressed wholesale energy market prices as a result of out of market programs like RPS and retail net energy metering – was substantial for southern Vermont and Southeast New Hampshire. The loss of 600 jobs in a rural region will have a large impact on the overall income, economic activity and housing prices in that part of New England. Additionally, the loss of a large base load generator will result in increase costs in the energy and capacity markets.

Most models used by solar DG advocates fail to account for the probability that more efficient allocation of capital within a net metering structure (i.e. a wholesale reimbursement rate instead of a retail rate) would generate more jobs and economic growth. This would also include funds taken from the private and public sectors through taxpayer and ratepayer subsidies.

A well-known example of a robust economic evaluation of solar is a comprehensive impact of solar generation policies on job creation and destruction in Spain. That study[vii] found that for every new job solar created, it cost the rest of the economy two jobs in the private sector. While a few benefit from the generous amount of funding thrown at the solar industry (via ITC, grants, net metering, property tax abatement, etc.) the overall impact is a net drain on the economy as a whole, requiring vast numbers of ratepayers and taxpayers to support an inefficient allocation of capital.

In addition to the one-sided look at the impact on employment, studies typically highlighted by solar DG advocates have a very large flaw. Most of these studies are based on IMPLAN economic analysis. The flaws in IMPLAN analysis is well known and documented, but a cursory look at the IMPLAN "multiplier" used in a particular study is usually the best indicator as to how exaggerated the outputs are. An IMPLAN multiplier of anything over 1.2x is considered far too generous in projecting economic benefits.[viii] Despite this economic reality, many renewable and energy efficiency studies continue to abuse the models by assuming multipliers of 2, 3, 10 or even 19.4 x the economic benefit for each dollar spent. It is my opinion that any study with a multiplier effect above 1.2x should be dismissed and ignored outright.[ix]

Q. What avoided compliance benefits are provided by distributed generators?

A. None. RGGI, which currently costs New Hampshire Ratepayers approximately 1 mil per kWh is already accounted for in the LMP so there are no additional avoided compliance costs by DG. Additionally, further penetration of DG and renewables on the grid will likely have a counter-intuitive effect on carbon dioxide emissions, which increased by 7% from 2014 to 2015[x] despite an increase of renewables on the grid. This counterintuitive result was largely due to the closing of the emissions free Vermont Yankee nuclear plant (this trend will most likely continue when the Pilgrim Nuclear Plant closes in May of 2019). It is well-documented that the more we integrate renewables into the grid the more the grid needs additional fast-start units cycling on spinning reserve potentially increasing emissions. At a recent forum in NH, Gordon van Welie, CEO of ISO-NE, stated in other countries that have a large percentage of renewables such as Spain and Denmark, have a MW for MW in "backup generation" that can come on-line when the renewables are not available. Of course, these additional resources come at a cost to ratepayers. He went on to say that costs will go up as the amount of renewable generation increases. Claims that supporting a retail net energy metering policy will result in lower emissions sounds good in theory, but in reality is unfounded. In addition, baseload power generators like nuclear and large scale hydro do not receive additional compensation for carbon dioxide free electricity and just as importantly they don't require fossil-fueled combustion turbines to be on spinning reserves and available should the sun stop shining or the wind stop blowing. Unless we want to expand the inequality of how we treat generation options in the state and in the region, including avoided compliance benefits in the net metering tariff would not be justified.

Q. Should any "external" benefits be included in a new net metering or alternative tariff?

A. Many advocates for solar generation argue that the net metering tariff should include compensation for the other "externalities" where solar provides a benefit. The bulk of the external benefits argued for include the presumed benefit of generation from a carbon dioxide free source and the economic impacts that solar installation provides for the state.

“Externality” compensation for the presumed benefits of some renewable/carbon dioxide free generation already takes place in abundance here in New Hampshire. Our Renewable Portfolio Standard already includes Renewable Energy Credits (RECs) for every kWh of electricity generated by solar in the state. The current requirement is for 0.3% of power generated in the state to be from solar (Class II obligations under the current RPS). According the NH PUC website, for 2016 the Alternative Compliance Payment rate for Class II in 2016 was $55.72/MWh. (This represents a maximum price. The actual price of solar RECs is now in the $30/MW range)

In addition to this direct benefit, the Regional Greenhouse Gas Initiative provides an indirect benefit to solar generation by imposing a higher cost of generation on more traditional forms like coal or natural gas. By making these forms of large-scale base load power more expensive and raising the Locational Marginal Price, it artificially makes solar power more cost competitive and an incrementally more economical source of electricity.

Solar generation also receives benefits from the state and local governments outside of the electricity markets. The federal government provides solar generators with an investment tax credit of 30% of the installation cost. At an assumed 50MW of installed capacity and using a per watt installed cost of $4.27[xi], this equates to over $64 million of tax credits for solar DG systems in New Hampshire.

Many local governments also provide local property tax abatements for solar generation, abatements that are not available for traditional forms of electricity generation. Again, assuming an installed cost of $4.27 per watt, 50MW would equate to $213 million of installed value, a significant percentage of which has been allowed to be ignored for local property taxes. Using the 2015 average statewide tax rate of $22.69 (using 239 town/municipal tax rates as posted at the NH DRA) this equates to up to $4.8 million in avoided property taxes by solar generation.

Finally, solar generation in the state also receives the benefits of participating in the Renewable Energy Fund Rebate Program. Under the program guidelines, residential solar DG is eligible for $0.50 per watt up to a maximum of $2,500 or 30% of the cost of the installation, whichever is less. In FY16 there was over $3.5 million awarded to 1080 applicants covering residential solar and wind. These funds are directly supported by all the electricity users in the state through their electric bills, again cost shifting from those that do not have solar generation to those that do.

In just the programs outlined here, solar DG receives on the order of $5-10 million of direct and indirect subsidies annually coming out of the pockets of ratepayers and taxpayers, in addition to something on the order of $64 million in federal tax credits to install the systems. It is clear that solar DG is already being heavily compensated for the value of the “externalities”. It is extremely unnecessary and unwarranted to impose even more “externality” charges on ratepayers through a net metering tariff. If the solar DG advocates feel that the current externality compensation is not enough, they should seek additional compensation through legislative channels and not attempt to hide it through net metering cost shifting via electricity bills.

Q. Current net metering policy allows for DG customers to "bank" electricity sold back into the grid and to be credited at a later date. Is the grid capable of storing power to be used at a later date?

A. The current process for accounting for and compensating under the existing net metering tariff operates differently for each utility. Each utility has a different process for metering the demand and production on site, estimating the Kwh of electricity generated on site, and then crediting or making payment to the customers.

One of the underlying problems with the current structure is that without real-time monitoring of the actual amount of electricity generated on site, the time that electricity was generated and the amount of electricity consumed on site, gross estimates are made as to how much and how valuable was the electricity produced. For example, Eversource data on net metering indicates that the utility does not track actual generation by the individual DG locations. Instead, their data shows that they account for the generation by using a blanket capacity factor multiplied by the installed capacity, and credit the end users by that amount. It appears that the utility does not even account for the seasonality of solar generation, assuming that generation in the winter is the same as generation in the spring or summer.

The result of this is comparable to considering that the grid acts like a battery. In effect, by using a broad capacity factor adjustment and ignoring the real time and seasonal nature of solar generation, the net metering customers are compensated in December for electricity generated in June. This is analogous to someone generating when power is relatively cheap, storing the power, and then selling it when it is more expensive. Except, unless the net metering customer has extensive storage on site, the excess electricity produced is pushed into the grid and is consumed in real time. Thus, the current accounting for net metering has the same effect as “using the grid as a battery”, even though this is not reflective of how the grid actually works.

The solution to this “grid as the battery” problem is to measure the actual generation and demand by net metering customers as close to real time as possible, recognizing the cost and limitations. At the same time, it should be recognized that every other non-DG generator in the New England region who sells electricity into the grid has to monitor and track their production on a real time basis. That is how they are compensated for the power they generate. If solar DG wants to sell their power into the grid, they should be held to the same standard to the greatest extent possible. Daily, hourly or real time generation data is certainly possible using current technology. It is also possible to identify the location of the generation and the price at that location at the time of generation. It is up to the PUC to identify what is the most reasonable solution, but we would argue that anything less than <u>daily</u> tracking and location specific LMP would only continue the fallacy of the grid as a battery that currently permeates net metering in the state, and extends the cost shifting from non-solar customers to solar generators.

Q. Are there clear locational benefits to DG?

Possibly, but that should be evaluated on a case-by-case basis. Advocates for solar DG continually argue that there are significant locational benefits that are provided to the local loop when solar is installed. For example, in the Acacia study looking at net metering benefits in Maine, the paper indicates that there is $0.04/Kwh of benefits provided by solar on the distribution system. Unfortunately, for ratepayers, the exact nature and the quantification of how they arrived at that number is typically lacking in most analysis of the localized benefits of DG.

In fact, most assessments of this type do not consider the additional costs that are imposed on the local grid, especially in cases where a particular local loop has substantial amounts of solar installed. This is a real factor here in New Hampshire as the data provided by NHSEA indicates that over half of solar installations in the state have occurred in only 50 towns. Five of the top 10 communities with the highest household income in the state are part of the 50 towns which have over half of the solar installations.[xii] Only 2 of the bottom 50 communities with the lowest household income are part of that group. This should not be surprising as solar installations are typically biased towards higher income cities and towns. In the case of Hawaii, as mentioned above, this problem has forced additional fees/tariffs on solar DG to ensure that the local grids can be properly maintained. Compensating net metered solar at retail rates is a transfer of money from those in apartments, mobile homes, smaller houses or anyone who is worried about paying their mortgage to those who are affluent enough to pay the upfront costs of solar installation. It benefits large consumers of electricity. Residential customers with central air conditioning, swimming pools and hot tubs (or those who just do not strive to conserve electricity) are the logical customers for solar installation. For a typical ratepayer using 500 kWh/month or less, solar installation is just not economical. Paying retail rates for net metering is a “take from those who have less and a give to those that have more” program. How do we justify a higher electric bill for a retired person on a fixed income living in an apartment in order to subsidize someone with a six figure salary living in a 4,000 square foot house with central A/C?

Beyond the direct costs that overburdening local loops with DG may cause and should be factored into any calculation of locational benefits, it is incumbent for solar DG advocates to show that solar installations are the least-cost option for the improvement of the local loop. Much like the way transmission upgrades are considered, it is the least-cost option that is permitted to be charged to the ratepayers. Any solution over and above that least cost option must be borne by parties other than the ratepayers. For the case of solar DG, the same rules should apply. Unless solar DG can show that they are the least-cost option to solve a problem on a local loop, they should not receive compensation (via an "adder" to a net metering tariff) that reflects an assumed benefit.

Most importantly, it is incumbent that the DG provider bear the burden of proof regarding specific locational benefits of a DG installation. It is generally recognized, and in practice is shown, that incremental installations on a particular local loop provide smaller benefits to that local loop. While the first installation may provide some marginal operational benefit (typically via an assumed deferral of local loop upgrades) the 30^{th} installation on that same local loop will likely not provide any benefit and may end up providing additional costs by requiring upgrades at the local substation in order to move electricity elsewhere in the grid at times of high solar generation.

Unless and until the solar DG customers can provide this type of value analysis that quantifies the actual benefit, and as stated above the burden of proof is on the DG customer/installer, then no consideration for locational benefits should considered as part of the net metering tariff.

Q. You consider the current net metering tariff as a cost shift from non-solar electricity customers to solar distributed generation customers. Can you quantify what you believe that cost shift represents?

Specific quantification of the statewide cost-shift due to the current net metering structure is impossible. Unfortunately, several of the utilities do not properly track the actual electricity generated and provided to the grid by solar DG customers. As indicated above, some of the utilities (i.e. Eversource) use gross estimates that don't account for the actual amount of generation on a particular day or month, the time of day the power is generated or the actual LMP (the alternative option for sourcing the electricity) when the power is provided to the grid. What we do know is due to the physics of solar panels and the track of the sun, their peak production does not occur at time of peak demand. The efficiency of solar panels drops as temperatures go up resulting in lower production in the peak demand months of July and August. Additionally, solar incidence peaks at 1:00 pm in the summer while peak demand occurs around 2:30 to 3:00 pm

Because of this shortfall in the available data, we can make a gross estimates using two methodologies. First, using Unitil's more "robust" data of the monthly "banked" solar generation for 2015, we can calculate a differential between the retail net metering tariff and the actual average LMP (New Hampshire zone) for the month it was generated. In this case

Unitil's non-solar customers appear to have paid $55,031 more in 2015 for the solar DG electricity than they would have paid if Unitil had purchased power at the LMP.

Looking at Eversource's data, we can make a much more gross calculation on the amount of the cost shift by its non-solar customers to solar DG. In their case, Eversource provides only a monthly "kWh Purchased" on their system which equates to a smoothed calculation of the number of kWh generated by DG per month on its system. We then used the banked figures from Unitil to extract an average percentage of generated electricity which was pushed into the grid on a monthly basis. By applying these percentages to the Eversource data, we can estimate how many kWh of excess generation in Eversource's territory was provided to the grid. We can then use the differential between the retail net metering tariff and the average LMP for each month to make the assumption as to the size of the cost shift. For 2015, for the Eversource territory, this would equate to $289,828.

Clearly, by these calculations hundreds of thousands of dollars each year are being shifted from solar DG to non-solar electricity customers. Unless and until the net metering tariff is brought more in line to the LMP, this cost shift will continue to rob Peter to pay the very wealthy Paul who could afford to put solar panels on his roof.

Q. Given the information you have provided here, what do you recommend as a net metering tariff?

The New England Ratepayers Association believes the proper tariff structure should be:

Tariff = (LMP * Kwh) + TD – IC - LFC

Where the tariff is comprised of:

LMP = Locational Marginal Pricing over a period of time

Kwh = the amount of electricity generated over the LMP period

TD = the net quantified benefit (or cost) of having solar generation on that node

IC = a flat interconnection charge that represents the value of an interconnection to the grid

LFC = Load forecasting costs

This tariff structure properly compensates the generator for the value of the electricity when it is produced, plus any marginal benefit that integration of the distributed generation can provide to the local distribution/transmission systems, while charging the distributed generation site for the value of interconnecting to the grid and the incremental costs of load forecasting.

(LMP * kWh)

This element of the tariff is simply the locational marginal price at a particular time multiplied by the amount of electricity (in kWhs) that is generated over that period. While the ideal environment would make the increment of time as small as possible (i.e. 5 min LMP pricing at the node of the distributed generation), current metering practices by the utilities may make the ideal difficult to implement in the near term. The Public Utilities Commission should recognize the current limitations in metering and allow longer time increments to be used to meter ACTUAL generation by the distributed generators, presumably on an hourly or at worst daily period. At the same time the PUC should also implement a required phase in of better net metering practices that require distributed generators to incorporate better metering practices in order to receive compensation for their excess power. It is incumbent on all other generators to follow specific mandates when they interconnect to the grid to sell and move power to end users. Distributed generators have been given very loose criteria in comparison to traditional generation. Rules that require a better accounting of the actual generation that is pushed into the grid, the time of day that excess electricity is "sold" to the local utility and the real time LMP when that transfer takes place is required for proper price signals and compensation. The distributed generators must migrate towards this type of system in order to eliminate the current cost-shifting environment.

TD compensation

During the hearings on net metering and in the net metering analysis put forward by solar advocates, it has been suggested that solar power provides a benefit to the transmission and distribution system. Most of this benefit is presumed to be in the deferral of capital expenses to upgrade and maintain these elements of the grid. Providing a formal quantification of this "benefit" is incumbent on the advocates for distributed generation. Most of this benefit is derived by gross assumptions about future expenditures to maintain local distribution grids. For solar net metering to have a significant effect on the need for future transmission for New England, it must be in the thousands of MW range. Projections of future solar installation in all of New England as presented by ISO-NE, are in the 3,500 MW range by 2025. This is the total of all solar installations including commercial and industrial of which net metering is a small portion of. Additionally, the overwhelming majority of this will be located outside of NH. The amount projected to be in NH is just not large enough to have a significant impact on future transmission needs. Additionally, paying solar net metering customers for any assumed savings in future transmission costs would be providing them a method of compensation that no other resource receives. EE resources receive no direct compensation for the hundreds of millions of dollars in future transmission costs that they have shown to produce. New generators who negate the need for new transmission receive no compensation for doing so. Providing direct compensation to solar net metering customers would be out of line in how we treat all other resources.

The burden of proof in determining this value is upon the distributed generators and should not be assumed to be positive by the PUC. In addition, it is incumbent on the solar advocates to show that the installation of distributed generation on a local loop is the least cost option to provide that benefit. If there are other options that can defer that capital expenditure, then the solar generator is actually providing an incremental COST relative to other options and should have its compensation lowered accordingly.

But any evaluation of this “benefit” must also consider the potential direct costs of additional integration of distributed generation. Concentration of solar generation in a particular local distribution loop may require upgrading of either the local loop itself, or the substation infrastructure to allow for large amounts of electricity to be moved beyond the local loop. In these cases, where maximum output of the distributed generation exceeds the maximum load there may be an increase in distribution costs. This potential cost increases the more distributed generation is integrated into the electrical grid. Thus any TD compensation included in the net metering tariff should both quantify the actual benefits, but also decrease over time as incrementally more distributed generation resources are added to local loops.

Interconnection Charge

A critical component of DG generation is the interconnection with the grid. This interconnection has two aspects to it. The primary one is the ability of the customer to pull electricity from the grid when there is no power being generated on the premises, and the second one is to allow excess generation to be exported from the premises to the local distribution network.

Since net metering has been a somewhat new electricity resource, early on the utilities typically only used a single bi-directional meter to "net meter". The meter would not provide any information as to when the DG electricity was produced, how much was consumed on site and when, or how much was exported to the grid. Instead, the utilities would just make accounting adjustments for the net power produced over the course of the month and calculate how much to charge or credit the customer.

Unfortunately, the utilities and the net metering customers did not fully appreciate the full impact of the cost-shifting that would take place as net metering policies, along with other non-market policies, subsidized adoption of solar generation. The result of the single bi-directional metering was that fully understanding the time of day and amount of electricity generated and consumed on sight was lost. Now that the utilities, other ratepayers and the PUC recognize the need for a better understanding of the value of the electricity generated by net metering, it is incumbent on the PUC to require the proper equipment be installed at DG premises. This would either be a single meter which can properly track, record and send data on time of day generation/consumption, or two meters installed on site, one for tracking outgoing excess generation into the local grid (time, day and amount) and one for tracking consumption by the end user. It is only through the tracking of this information can the correct value of the electricity that is generated by the DG facility be determined and properly compensated. This will also ensure the end of the cost shifting that has been occurring due to the basic form of net metering that is mis-allocating the costs of net metering onto non-solar customers.

Of course, with a mandate to install the necessary equipment, the question arises as to who should bear the cost of the equipment and its installation. To answer this, we should look to which party bears the costs for interconnection of any traditional generator. For every other generator who exports power into the grid and receives compensation for that power, it is the generator who must pay for and install directly or indirectly. In the case of DG, there is no rational argument that would justify the utility (and the non-DG ratepayers) to pay for this equipment and installation. It should be incumbent on the DG providers, who are making a choice to interconnect for the purpose of exporting power, to pay for the second meter which must be able to track when power is exported to the grid and in what quantity.

Advocates for DG often argue that there are substantial benefits provided to the grid via the fact that DG can provide electricity to the local distribution loop. Much of this discussion and counter argument is included above. But what the advocates of DG fail to consider is the tremendous value that interconnection to the grid provides to DG. The interconnection to the grid is the ONLY way for a solar generator to receive any compensation for their excess power. It is that connection that actually enables the DG to export power at all, and it is the interconnections to the local loop, other end users and the local substation which provide the true value, not the DG itself.

In order to quantify this value, it is simple to consider the alternative cost to the DG end user without an interconnection to the grid. Consider a DG location which has a 4kw system and the end user consumes 600 Kwh per month. Also, given there is no interconnection to the grid for this location, we can assume the need for five days of electricity storage on site (this assumes five days of cloud cover resulting in no power generation from the solar array for that time). This would result in 100Kwh of storage required on site (600Kwh/30days = 20Kwh/day * 5 days = 100Kwh capacity needed). Current Powerwall capacity[xiii] is 6.4Kwh therefore 15 Powerwall units would be needed to ensure continuous electrical supply. The current cost of a Powerwall unit is approximately $3000 per unit, which would equate to a $45,000 "replacement cost" for the interconnection. Of course, the Powerwall units do have a limit in the number of cycles that they can operate, and while the Powerwall is somewhat new and the lifecycle limitations are subject to change, current data[xiv] indicates a 1000-2000 cycle life for $LiNiMnCoO_2$ batteries. This means that a system like this is likely to require complete replacement over a 10-15 year period whereas an interconnection to the grid is more or less permanent and does not require any additional up-front capital expense from the customer. Even ignoring this substantial life cycle cost factor, if we simply associate the cost of the initial Powerwall as the replacement cost of the interconnection, we find that the value of that interconnection is on the order of $75 per month over a 50-year period. While this value is based on gross assumptions, the PUC and the utilities should be able to better quantify this value. Given these economics, it is very difficult for the DG advocates to argue that the value of having the DG on the grid is worth more than having the grid interconnected with the end user.

Load forecasting costs

One element that DG supporters ignore is the incremental costs with load forecasting and real time electricity sales which are associated with DG. Most utilities must anticipate the forward demand of their customers and ensure through contractual agreements the electricity they need to serve that demand. In order to fill any incremental demand above the supply they have under contract, the utilities typically enter into the Day Ahead ("DA") market to secure the electricity they will need for the following day. In making their estimates for the DA load there is typically an assumption of the electricity which DG will generate. But due to the intermittency of the DG supply, both in terms of amount and time of day, the suppliers will have to enter the Real Time ("RT") market to balance their electrical supply with their load. If in fact, the solar DG are providing too little power than anticipated, the utility will have to purchase power on the RT market, likely paying a premium for that electricity as demand is exceeding supply at that point in time. If in fact, the solar DG is supplying more power than expected, the utility will have to sell a portion of the power they purchased in the DA market on the RT market, but likely at a loss as demand is now lower than anticipated supply. Management of this supply-demand matching process is likely costing the utilities, and thus non-solar ratepayers, as they would be either paying a premium for additional RT power purchases, or facing small losses on power they have during times of excess. It is beyond our abilities to quantify this real cost, and therefore we have not identified its specific value as part of a net metering tariff. The PUC and the utilities should be able to determine the correct calculation and value for this component of a net metering tariff. It should be noted that solar net metering customers do not have any obligation to generate. At any time, for any reason, they can go from a net producer of electricity to a net consumer. The supplying utility must build the distribution system to supply these customers when their demand is at its highest. Due lower total kWh consumption these costs must be obtained through higher distribution rates to all customers.

Q. Does this conclude your testimony?

A. Yes.

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[i] http://acadiacenter.org/wp-content/uploads/2015/10/AcadiaCenter_GridVOS_NewHampshire_FINAL_2015_0904.pdf

[ii] http://www.ksg.harvard.edu/hepg/Papers/2014/12.14/Brown%20%20Valuation%20of%20%20Distributed%20Solar%20%2011.14.pdf

[iii] https://www.bostonglobe.com/lifestyle/health-wellness/2013/08/27/vermont-yankee-nuclear-plant-close/JTX64k3YjBz7yrJnI40bVM/story.html

[iv] https://www.iso-ne.com/static-assets/documents/2016/09/gvw__nec_9_28_2016.pdf

[v] http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464

[vi] http://www.ksg.harvard.edu/hepg/Papers/2014/12.14/Brown%20%20Valuation%20of%20%20Distributed%20Solar%20%2011.14.pdf

[vii] http://instituteforenergyresearch.org/wp-content/uploads/2015/05/090327-employment-public-aid-renewable.pdf

[viii] https://www.documentcloud.org/documents/1148850-bhi-the-economic-impact-of-north-carolinas.html

[ix] Ibid.

[x] https://www.bostonglobe.com/metro/2016/05/15/carbon-emissions-rising-new-england-power-plants/9WfbtQMJEMBszzxPzf2OLO/story.html

[xi] http://www.nrel.gov/docs/fy15osti/64898.pdf

[xii] https://en.wikipedia.org/wiki/New_Hampshire_communities_by_household_income

[xiii] https://www.tesla.com/powerwall

[xiv] http://batteryuniversity.com/learn/article/types_of_lithium_ion