BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DE 16-576

ELECTRIC DISTRIBUTION UTILITIES

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

REBUTTAL TESTIMONY OF
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ON BEHALF OF
THE ALLIANCE FOR SOLAR CHOICE

DECEMBER 21, 2016

Executive Summary

This rebuttal testimony on behalf of The Alliance for Solar Choice (TASC) addresses the proposals of certain other parties responding to the Legislature's direction in House Bill 1116 to develop new tariffs for net energy metering (NEM) in New Hampshire. The stated goals of HB 1116 are, first, to continue to allow reasonable opportunities for electric customers to invest in and to install renewable distributed generation (DG) behind the meter on their own premises; second, to provide fair compensation for this locally-produced power; and, third, to allocate the benefits and costs of these new, clean energy sources in a fair and transparent way among all ratepayers.

The first requirement of HB 1116 is that the Commission consider both the benefits and costs of renewable DG. The proposals of the utilities generally have not provided a comprehensive review or calculation of the long-term benefits of these new renewable resources, and have focused largely on the short-term cost of service for DG customers. Even these cost analyses are flawed. First, DG customers are not so different from other customers that they should be placed in a separate customer class. Installing solar generally converts a larger-than-average residential customer into a smaller-than-average one, but both before and after adding solar, DG customers are well within the typical range of sizes and load factors for residential customers. Second, DG customers should not be subject to a rate design based on non-coincident demand charges, as proposed by Eversource and Unitil. This rebuttal shows that such a structure is not cost-based for DG customers, and fails to reflect the capacity-related benefits which DG provides to the utility system. Volumetric time-of-use (TOU) rates are a more accurate, cost-based, and understandable rate design for small customers.

There are also important practical and customer acceptance reasons not to mandate three-part residential rates for DG customers in New Hampshire. The utilities lack the advanced metering, information systems, and customer education programs that are the prerequisites necessary to provide the data and knowledge needed if customers were to be required to understand and evaluate DG investments under demand-based rates.

This rebuttal also reviews other recent cases in which utilities elsewhere in the U.S. have proposed mandatory three-part rates including demand charges for residential customers. No other state commission has adopted a mandatory three-part rate, either for all residential customers or for those that install DG. It would be unwise for the Commission to do so in this proceeding.

The utilities and the Office of the Consumer Advocate (OCA) have also proposed new NEM tariffs that include significant reductions in the rate credit for exports from DG facilities. The utilities' proposed reductions in the export rate all fail to consider the long-term avoided costs of renewable DG, including the reductions in marginal transmission and distribution (T&D) costs that will result from the fact that DG output either serves on-site loads, never touching the grid, or is consumed by the DG customer's neighbors, thus making upstream T&D capacity available to serve load growth or other customers. OCA is on the right track in proposing that the new NEM tariff should focus on a cost-based, volumetric TOU rate. However, OCA's addition of a new, offsetting charge to the export credit would result in charging DG customers for a service which they are not using. It is the utility, not DG customers, who uses the distribution system to deliver the exports from DG systems, and the utility is fully compensated for providing this service.

TASC does not oppose the removal of public benefit charges from the export rate, on the equitable grounds that all customers should pay for these important programs on the same basis of the amount of power which they draw from the system. However, the Commission should reject OCA's proposal to treat a portion of transmission costs as non-bypassable. This proposal inappropriately cherry-picks just one cost category (transmission), and fails to consider that, even if the marginal transmission costs avoided by DG do not equal embedded transmission costs, this shortfall is compensated by generation-related benefits that exceed the generation costs in rates.

OCA also has proposed a Fixed Credit Rate option for NEM customers, which would provide DG customers with a fixed delivery credit for their entire output, plus the default energy supply rate and fixed compensation for transferring renewable energy credits (RECs) to the utility. The Fixed Credit rate would decline in a series of pre-set steps that are supposed to track the decline in solar costs. This proposal has the positive feature that the credit is fixed for 20 years, providing important certainty to support DG investments. However, the Fixed Credit rate relies on the transfer of the REC to the utility to come close to being economically viable. Finally, in order to maintain a customer's right to self-consume power, which is based in PURPA, the Fixed Credit rate should be available either for exported power alone or for a DG customer's entire output, at the customer's election.

TASC supports the testimony of the New Hampshire Sustainable Energy Association (NHSEA) that small DG customers need to have a better means to aggregate and realize value from their RECs. Small-scale DG provides significant benefits to other ratepayers if RECs are transferred to the utility, and this benefit must be considered to the extent that the utilities use DG RECs to comply with the New Hampshire Renewable Portfolio Standard (RPS). Further, ratepayers realize an indirect benefit from lower costs to comply with the RPS requirement as a result of lower utility sales when customers install renewable DG, even if the REC remains with the customer. This indirect benefit further improves the cost-effectiveness of NEM in New Hampshire.

Finally, TASC has calculated the impact of the major utility and OCA proposals on the bill savings from residential DG. Many of these proposals would have substantial negative impacts on the economics of DG in New Hampshire, and thus would not comply with the goal of HB 1116 to continue to allow reasonable opportunities for electric customers to invest in renewable DG. This rebuttal and the long-term benefit-cost analysis that TASC has performed show that the best course is to maintain the basic structure of NEM, with a greater emphasis on volumetric, cost-based TOU rates and the equitable removal of public benefit charges from the export rate.

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Appendices

I. INTRODUCTION

Q1: Please state for the record your name, position, and business address.

A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q2: Have you previously presented testimony in this docket?

A2: Yes, on October 24, 2016, I served direct testimony in this docket on behalf of the Alliance for Solar Choice (TASC). My experience and qualifications are described in my *curriculum vitae,* which is attached to that direct testimony as **Appendix A**.

Q3: What is the purpose of this rebuttal testimony?

A3: I address the proposals of certain other parties to implement new tariffs for net energy metering (NEM) in New Hampshire, pursuant to the Legislature's direction in House Bill 1116 (HB 1116). The stated goals of HB 1116 are, first, to continue to allow reasonable opportunities for electric customers to invest in and to install renewable distributed generation (DG) behind the meter on their own premises; second, to provide fair compensation for this locally-produced power; and, third, to allocate the benefits and costs of these new, clean energy sources in a fair and transparent way among all ratepayers. This rebuttal discusses why some of the filed proposals fail to meet these goals, while others require modification to attain them. As set forth in my opening testimony, the goals of HB 1116 can best be realized by retaining the present structure of NEM in New Hampshire, with certain changes to remove public benefit charges from export rates and to move to the greater use of volumetric time-of-use (TOU) tariffs that bring rates closer to costs and that are simple and straightforward for residential and small commercial customers to understand.

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II. DEMAND CHARGE PROPOSALS

A. Eversource / Unitil Proposals

Q4: Please describe the rate design changes that Eversource and Unitil have proposed for residential and small commercial customers who install renewable DG.

A4: Both utilities propose to implement separate three-part rates applicable only to customers who install DG. These rate designs would include demand charges covering certain delivery costs. These rates would begin to be applicable upon the conclusion of this proceeding and immediately after each utility reaches its share of the state's original 50 MW net metering cap.

Unitil would place residential DG customers into a separate class, and, based on a cost-of-service study, would increase the fixed customer charge and implement a demand charge to recover distribution costs based on the DG customer's maximum 15-minute demand whenever it occurs. In other words, it would implement a non-coincident demand charge to recover distribution costs from DG customers.[1] However, the actual demand charge for DG customers that Unitil is proposing to implement at this time appears to be based on the allocated costs for the entire residential class, not those specifically allocated to DG customers.[2]

Similarly, Eversource proposes to implement a new three-part rate solely for DG customers, including a demand charge to cover both transmission and distribution costs. The new demand charge would be based on Eversource's current cost-of-service study for residential and small commercial customer; the utility would not consider creating a new class for such customers until its next rate case. Eversource would simply convert the present volumetric (per kWh) distribution and transmission rates of its existing residential (Rate R) and small commercial

[1] See Unitil Testimony (Oversource Supplemental), at Table 1. Also, Unitil Testimony (Meissner), at pp. 45-47.
[2] See UES Schedule HEO Supplemantal HEO-2 [sic] at Sheets 2 and 5.

rate schedules (Rate G) to a per kW demand charge using the same revenue requirement now allocated to these classes. Like Unitil, Eversource would require new DG customers to have metering capable of recording the customer's 30-minute imports, exports, and maximum demand on the grid.

Both utilities also would change the rate credit provided for the power which DG customers export to the grid to a short-run avoided cost price. These proposals are discussed in Part III of this rebuttal.

B. Cost-of-Service Analyses Fail to Capture Long-Term Benefits.

Q5: What is the essential flaw in the Unitil and Eversource proposals?

A5: The first requirement of HB 1116 is that the Commission examine the benefits and costs of customer-sited DG facilities. The rate design changes that Unitil and Eversource propose do not comply with this foundational requirement. The two utilities have proposed changes to NEM in the form of required new rate designs for DG customers that are based solely on a cost-of-service analysis, without consideration of the benefits of DG, except for an export credit based on short-run avoided energy costs. As set forth in TASC's opening testimony, DG is a long-term resource with a service life of 20 – 30 years that will produce an array of long-term benefits for the electric system in New Hampshire that Unitil and Eversource have failed to consider.

C. DG Customers Should Not Be in a Separate Class.

Q6: Please respond to Unitil's proposal to place residential DG customers into a separate customer class.

A6: Unitil's witness Overcast justifies the placement of DG customers in a separate customer class based principally on a comparison of two hypothetical customers, one with DG and one without, that are the same size before adding DG.[3] This is not standard utility practice for establishing a new customer class, which generally involves an examination of load research data on the actual hourly loads of the two types of customers from a representative sample of customers, including data on customer size and load factors, to demonstrate that the new class is distinct from other customer classes. In discovery, Unitil admitted that it does not have hourly load research data on its DG customers. All that Unitil was able to provide was monthly billing data for deliveries and exports to and from DG customers, plus their maximum demands but with no data on when those demands occur. None of the New Hampshire utilities have the basic 15-minute or hourly load research data on their residential and small commercial DG customers that should be used to analyze whether DG customers belong in a separate class or to conduct an accurate cost of service study with data for DG customers that is of a comparable quality to what is used for other customer classes.[4]

Q7: Does the available data on Unitil's DG customers support that they are significantly different than other residential customers?

A7: No, it does not. In addition to the monthly billing data for DG customers, Unitil provided TASC with its load research data for regular, non-DG residential customers. This data shows that, in terms of size and load factors, DG customers remain within the range of other residential customers, even after adding a DG system. **Figure 1** shows the average monthly usage of Unitil's residential DG customers both before and after installing solar, compared to the average and range of monthly usage for all of Unitil's residential customers.[5]

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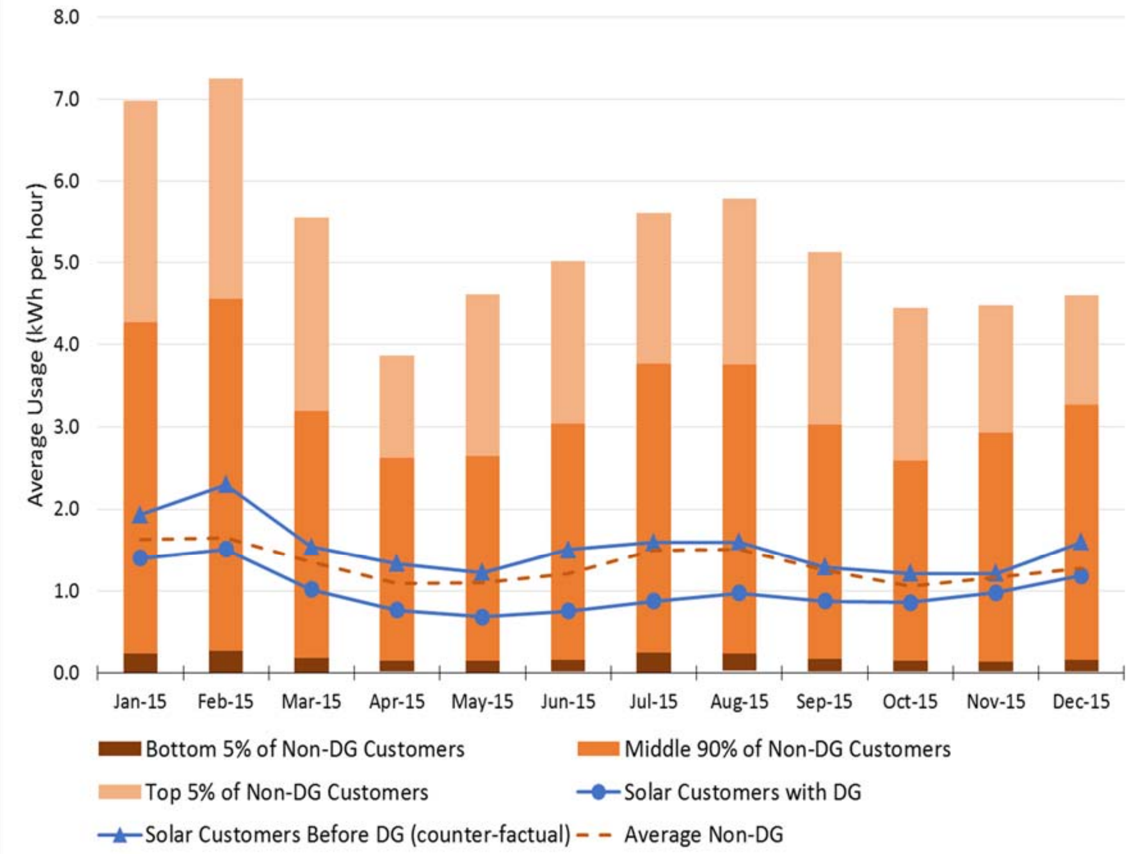
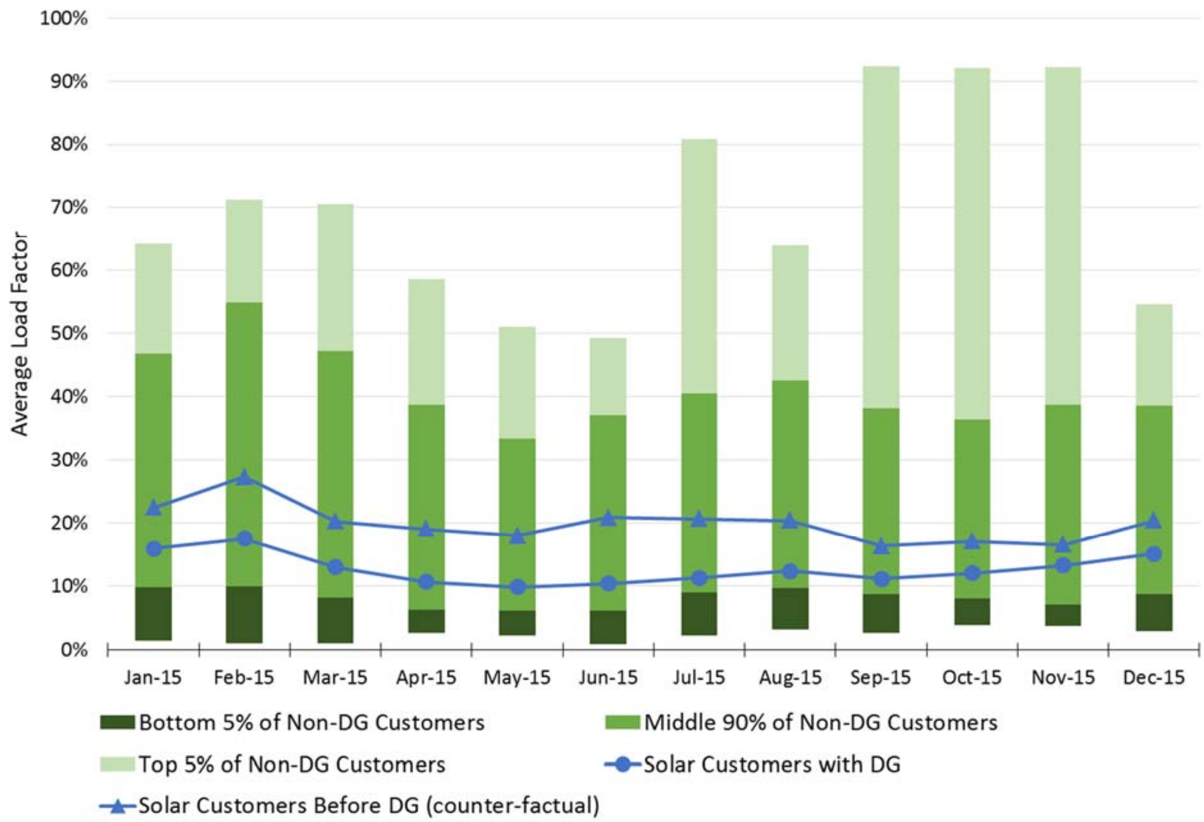
3 Unitil Testimony (Overcast Direct), at pp. 18-21.
4 See Eversource and Unitil responses to Data Requests EFCA-TASC 1-002.
5 The data in Figure 1 for solar customers, before DG is installed, was obtained from the workpapers of Unitil's Mr. Overcast. See the "Metered Data" tab of the "Unitil Counterfactual Load Derivation vs 08-03-2016.xlsx" Excel worksheet. Mr. Overcast developed "Full Requirement Load" amounts for DG customers by summing actual billing data on DG customer usage and simulated data on DG customer solar production.

Figure 1: Unitil Residential Customer Usage by Month



Similarly, **Figure 2** shows the monthly load factors for DG customers, before and after adding solar, compared to the range of load factors for Unitil's residential class as a whole. Again, the figure shows that DG customers, both before and after adding solar, remain within the range of monthly load factors for the residential class as a whole.

Figure 2: Unitil Residential Customer Load Factors by Month



Q8: Are you surprised with what this data shows?

A8: No, I am not. Unitil's Mr. Overcast observes correctly that residential end use profiles have become more diverse over time as the array of different uses for electricity has proliferated.[6] This trend is certain to continue, with new loads such as electric vehicles, expanded use of electricity for space heating, controllable water heating, new "smart" ways to control the timing of electric use (smart inverters and thermostats), and on-site battery storage. In the long-run, it will not be practical, efficient, or customer-friendly to create new customer classes for each new customer-driven technology or combination of technologies that can change significantly the magnitude or the hourly shape and timing of electric use. Instead, it will be best to set cost-based, easily understood rates that reflect how

[6] *Ibid*., at p. 18, lines 12-20.

costs vary by season and time-of-day, and allow customers and new technologies to respond accordingly.

D. Non-Coincident Demand Charges Are Not Cost-Based.

Q9: Are cost-based rates a central goal of utility rate design?

A9: Yes. For example, a commonly cited list of the goals for utility rate design is set forth in Professor James Bonbright's *Principles of Public Utility Rates.*[7] The Bonbright principles enumerate eight central qualities of a just and reasonable rate structure:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

6. Fairness of the specific rates in the appointment of total costs of service among the different customers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service.

The sixth Bonbright principle of "fairness in apportioning cost of service among different consumers" generally is taken to mean that rates should be based on the costs which customers cause the utility to incur.

[7] James Bonbright, *Principles of Public Utility Rates*, 291 Columbia University Press (1961).

Q10: Is it cost-based to design rates for residential solar customers that include a non-coincident demand charge to cover capacity-related distribution costs, as Unitil and Eversource are proposing?

A10: No, it is not. As explained in TASC's opening testimony, if a significant portion of the utility's costs are collected through a non-coincident demand charge that does not depend on the time when the customer imposes a demand, DG customers may see little reduction in their bills for the costs covered by the demand charge. This relatively small change in their bills does not compensate solar customers for the capacity-related costs that their on-site generation avoids. DG customers are likely to incur a significant demand charge for the entire month on a cloudy, low-demand day with low PV output, or by spiking a significant demand first thing in the morning – both times when system demand and solar output are low. The customer's resulting monthly bill will fail to recognize that the same customer contributed significant capacity on the hot, sunny, high demand days of that same month, and thus the utility avoided significant transmission and distribution capacity-related costs.

Q11: What are the key flaws in the utilities' demand charge proposals?

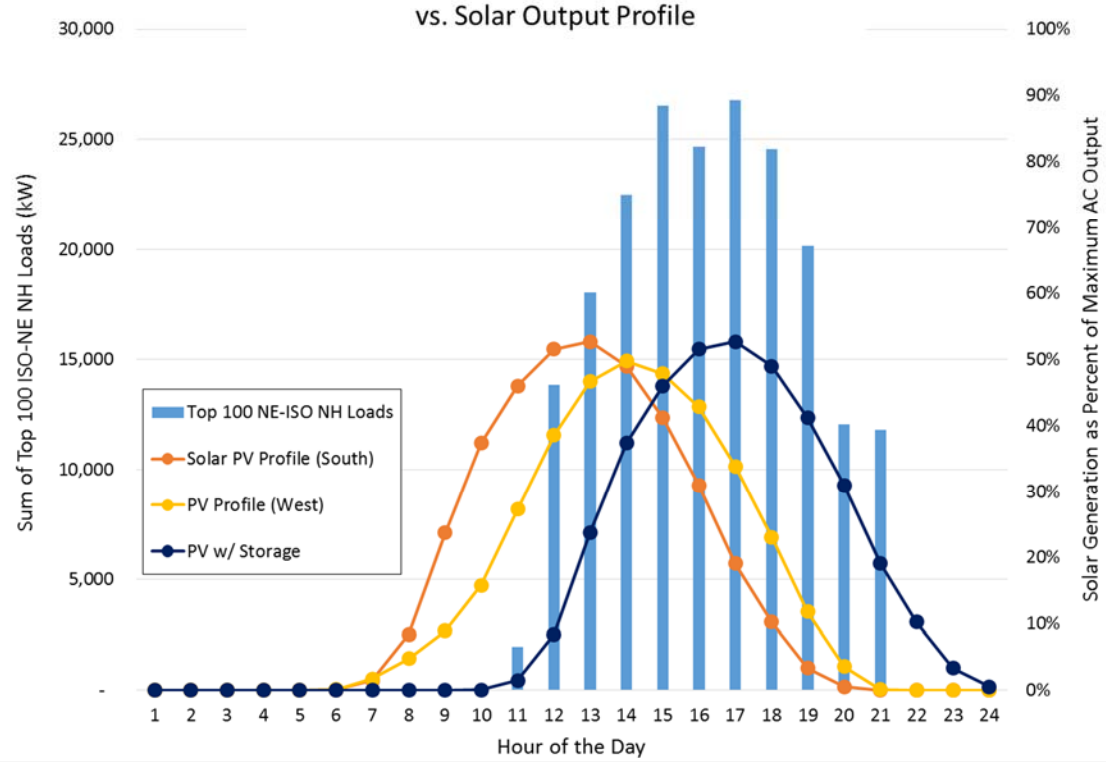
A11: Two key factors are missing. The first missing factor is time; the second is diversity. I will explain each failing in turn.

1. Time

Q12: Why is the factor of time important?

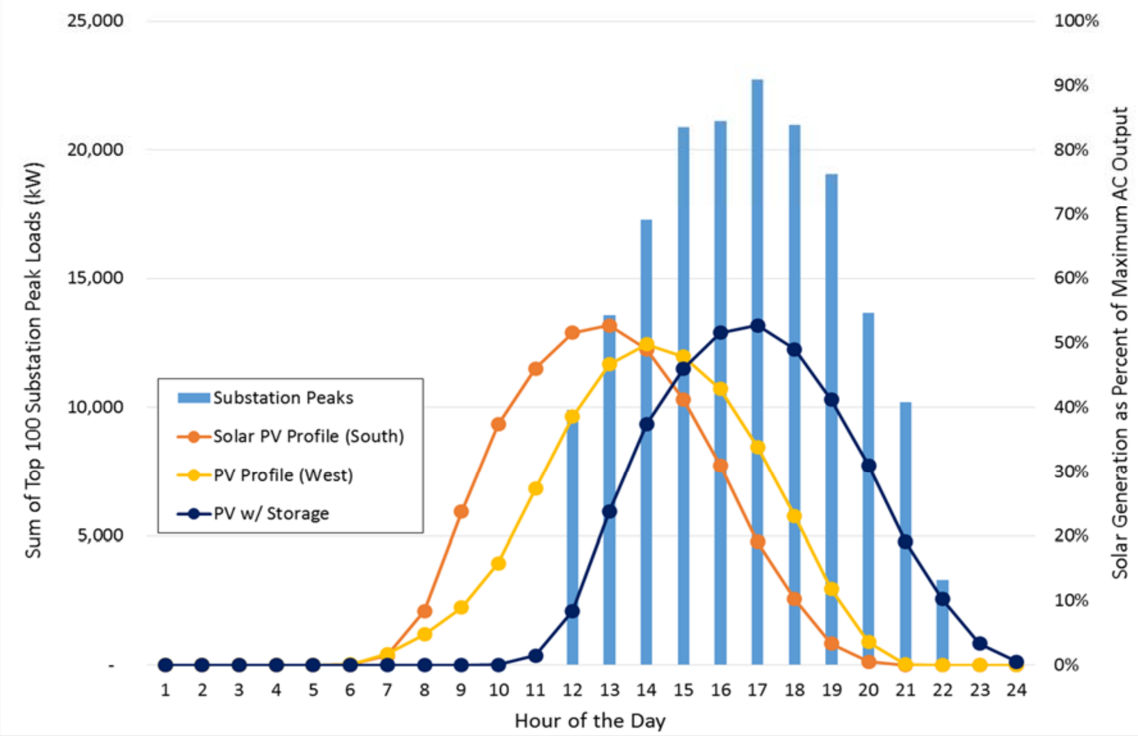
A12: Utility costs, including distribution system costs, are highly dependent on the time of day and the time of the year, because a significant portion of utility costs are related to providing adequate infrastructure to maintain reliable service during the times of highest customer usage. Such costs are characterized as "capacity-related" because they are driven by the need to provide the capacity for the utility to serve the peak demand. As a result, customers only cause capacity-related costs to be incurred if they use power in the months and at the times of day when the demand for electricity is high. **Figure 3** below shows that there is significant correlation between when the overall electric system in New Hampshire peaks (as measured by the top 100 load hours) and when solar DG produces power. Thus, the contribution of a solar PV resource to generation capacity is an appreciable share (40% to 50%) of the solar resource's nameplate capacity, as discussed in conjuction with the "load match factors" developed in Exhibit D of TASC's opening testimony.

Figure 3: Distribution of NH NE-ISO Loads by Hour vs. Solar Output Profile



The correlation with distribution system peaks is not quite as strong as with system peaks, but is still significant, as shown in **Figure 4**, using Eversource data. These figures also show that west-facing PV systems and solar-plus-storage can further enhance the ability of renewable DG to avoid capacity-related costs.

Figure 4: Distribution of Substation Peaks by Hour vs. Solar Output Profile



Q13: Is it cost-based to assess a demand charge on residential customers based on the customer's maximum use in any hour?

A13: No, it is not. First, Figures 3 and 4 show clearly that the capacity-related transmission and distribution costs which Eversource and Unitil would include in the demand charge are driven by usage in the afternoon and early evening hours, not morning or nighttime hours. As a result, it is not reasonable to impose a demand charge on residential customers based on their maximum demand in any hour. Such maximum demands may occur outside of the hours that drive the utility's costs. For example, a residential customer could hit a monthly peak demand in the morning getting ready for work and school at a time when demand is low on both the local distribution system and the overall utility system. More generally, as discussed next, the diversity in the loads of small customers means that non-coincident demand is a poor measure of many of the costs for local and system capacity which such customers cause the utility to incur.

2. Diversity

Q14: Is it reasonable to base rates on an individual customer's maximum demand, without consideration of the time element, because there is less diversity as one moves down the utility system to the system elements closest to the customer, as Unitil's Mr. Overcast argues?[8]

A14: No. Obviously, there are electric system components closest to the customer that are sized considering the customer's individual maximum demand, such as the meter, service drop, and the final line transformer. However, there is significant diversity on the rest of the utility system, particularly on the portions that serve large numbers of smaller customers. This diversity underscores the importance of the time element. On an electric system with customers numbering in the tens of thousands or hundreds of thousands, or on a distribution circuit with hundreds or thousands of customers, the addition or subtraction of an individual customer's load will not change when the system or circuit peaks. It is simply a fact that using power in the hours of peak demand is more consequential for the utility's marginal costs than usage at other times, and rates should reflect the importance of time.

Q15: Unitil's witness Mr. Overcast acknowledges that the design of utility delivery systems reflects the diversity of customer loads.[9] Does this diversity support a rate design for delivery costs based entirely on individual customer's maximum demand?

A15: No, it does not. There is significant load diversity, particularly on the upstream portions of the system (e.g. the transmission system, distribution substations, and higher-voltage distribution circuits). Where there is significant diversity, the utility serves the aggregate, diversified demand during peak periods. In designing

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[8] Unitil Testimony (Overcast Direct), at p. 24.
[9] *Ibid*.

rates to cover the costs of this portion of the electric system, there is no need, and indeed it can be unfair and inefficient, to base a customer's rate on its individual maximum demand. Instead, a customer's average demand (i.e. its volumetric usage) during a peak TOU period is a far better measure of a customer's impact on these costs than the customer's maximum 15- or 30-minute demand, which may not even occur in that peak period. This is particularly true for solar DG customers, whose individual demand is likely to peak at times of lower demand, either in the evening or on cooler, cloudy days.[10]

Further, the diversity of customer loads means that existing volumetric rates reasonably cover the utility's costs when customers momentarily draw more power than normal from the grid. For example:

- An individual customer can have a short-term demand spike, for example, when the air conditioner compressor starts, but the system can handle this because everyone's air conditioners do not start at the same time. There is a level of diversity on residential circuits with many small customers such that the utility does not have to plan to size residential circuits to serve the sum of the non-coincident demands of all residential customers on the circuit. Such diversity does not exist to the same extent on circuits which serve a much smaller number of large commercial or industrial customers, and thus non-coincident demand charges are more reasonably a part of commercial and industrial transmission and distribution rates. As a result of diversity, it is reasonable to collect distribution costs from residential customers based on their kWh usage (i.e. their average demand) over a summer peak TOU period that covers just the hours when distribution circuits are most likely to peak.

- Similarly, the electric system's geographic diversity allows it to manage a DG customer whose demand increases when a cloud shades his PV system, because another DG customer's system will be emerging into the sun at that same moment, or another customer will be decreasing their usage. It is possible that, as solar penetration increases, the aggregate variability of all solar customers' electric output may add to the variability of the loads that the utility must serve, and impose additional costs for regulation and operating reserves on the system operator. The costs of

[10] *See* CPUC Decision No. 14-12-080 (December 18, 2014), finding that the rate design for commercial solar customers should include reduced demand charges, for this reason. *See* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K631/143631744.PDF.

meeting this added variability is the focus of the solar integration studies that a number of utilities have conducted. Studies show that such costs are low at the current level of solar DG penetration in New Hampshire.[11]

- A utility does not "stand by" to serve DG customers in any way that is different than how it stands by to serve non-DG customers. The costs which the utility incurs to serve a solar customer are no different than those it incurs to stand by to serve a regular utility customer whose usage for periods may be very low – for example, in the middle of the day when the occupants of a house are away at work and school – but who may return home and suddenly impose a load on the system.

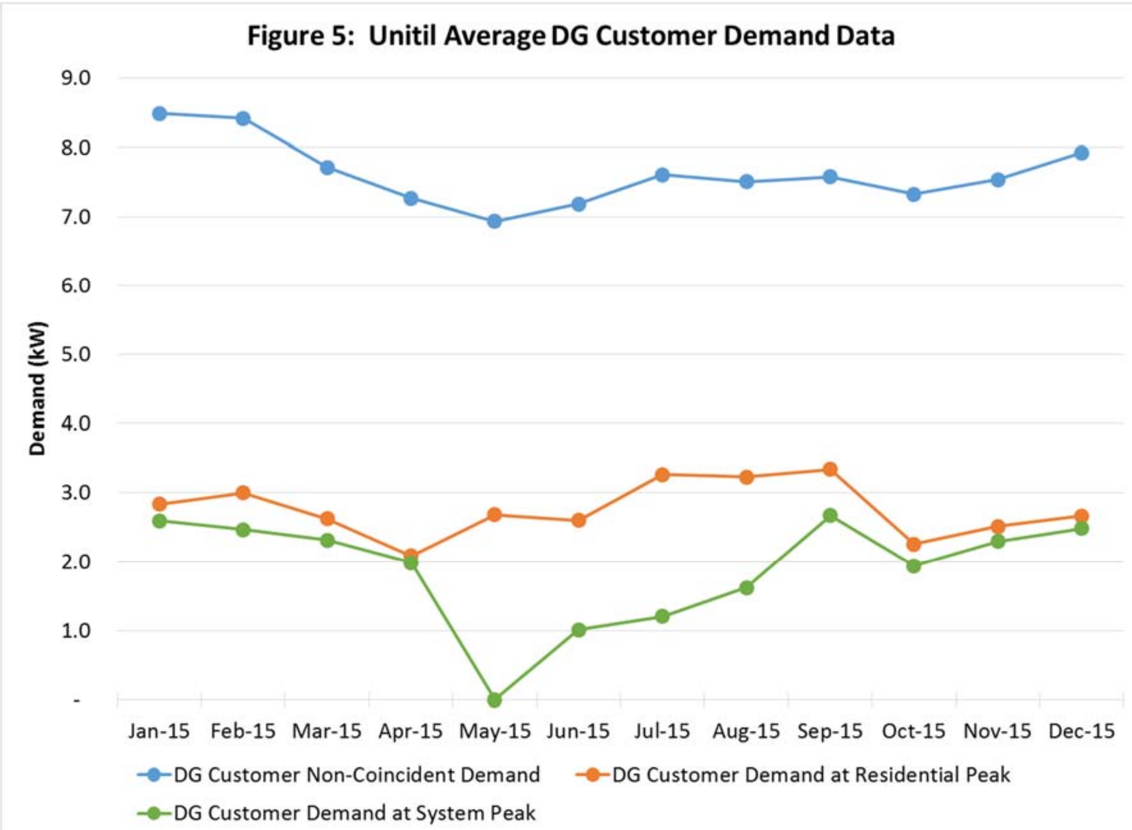
In sum, there is a level of diversity on residential circuits with many small customers such that the utility does not have to plan to size residential circuits to serve the sum of the non-coincident demands of all residential customers on the circuit. This diversity of small customers' loads allows the utility to serve the aggregate demand based on kWh usage without a need to implement a rate design that charges small customers based on their individual non-coincident demand.

Q16: Can you provide data from DG customers in New Hampshire that illustrates why the diversity of residential loads means that demand charges based on individual DG customer's noncoincident demand will overcharge them for delivery service?

A16: Yes. In discovery, Unitil provided 2015 billing data for its residential DG customers, including customers' monthly maximum noncoincident demand and their monthly imports and exports in kWh. Using the monthly billing data, we have developed an hourly profile for the net usage of the average Unitil residential DG customer, assuming that such a customer has the average residential load profile and installs a 6.5 kW solar system in Concord, which results in monthly imports and exports that are close to those of the average

[11] *See* TASC's Exhibit D study, at p. D-7 and Footnote 13, citing integration costs from the New England Wind Integration Study. Also see *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* (Battelle Northwest National Laboratory, March 2014), at Table 2.5 and Figure 2.51. This study calculates that, with 673 MW of solar PV capacity on the Duke utility systems in 2014, integration costs would be about $0.0015 per kWh.

residential DG customer in Unitil's billing data.[12] Based on the net load profile of this average DG customer, we compared the average DG customer's maximum noncoincident demand to their demand (1) coincident with the New Hampshire system peak each month (which drives transmission costs) and (2) coincident with the residential class peak load (which is a measure of cost causation on the distribution system). This comparison is shown in **Figure 5**.



The figure shows clearly that non-coincident demand charges that recover significant demand-related transmission and distribution costs driven by system or class peaks will overcharge NEM customers for the actual capacity-related costs which they cause. For example, looking at the data for July in Figure 4, DG customers have loads of 1.2 kW during the system peak hour that drives

[12] The assumed solar system size is based on the simulated solar production data from Mr. Overcast's counterfactual load workpaper referenced in footnote 5 above.

generation and transmission costs, and 3.3 kW at the time of the residential class peak, when significant distribution costs are incurred. However, if DG customers are charged for these costs based on their maximum non-coincident demand, they will pay such costs based on their 7.6 kW maximum non-coincident demand during the month, a demand which may not even occur in the hours when the system or the residential class actually peaks.

Q17: What rate design for residential customers would be more cost-based?

A17: For residential customers it is more reasonable to collect T&D costs based on customers' average demand over a summer on-peak TOU period that covers just the hours when the circuit is most likely to peak. This can be accomplished through a volumetric TOU charge to recover T&D costs during these peak hours. A customer's kWh usage over the peak period measures the customer's contribution to the average demand during those hours and would be a reasonable, cost-based charge. An even more accurate rate would be a Critical Peak Pricing (CPP) rate, which are volumetric TOU rates that charge very high on-peak rates to customers in a limited number of high-demand hours each year that the utility or system operator declare on a day-ahead basis.

Q18: Given new metering technology, should the Commission re-evaluate the role in rate design of traditional non-coincident demand charges?

A18: Yes. Fundamentally, measuring a customer's "demand" is simply measuring its energy use over a different, shorter time period (15 or 60 minutes) than the standard measure of energy over a time-of-use period or monthly billing period. Thus, a customer with a demand of 4 kW is really just using 1 kWh of energy every 15 minutes or 4 kWh of energy each hour. From this perspective, there is nothing inherently more accurate with charging customers for demand (kW) than energy (kWh). Nor is the maximum demand in a month necessarily significant for cost causation, unless it occurs at a time when demand on the system is high. Such maximum demand charges are simply the traditional way that utilities have charged large customers for certain costs. However, demand charges are increasingly obsolete because, with new metering technology, focused TOU rates will be much more accurate than traditional 15- or 60-minute maximum demand charges. Here is the perspective of one expert, Bill Marcus of JBS Energy, who has represented residential customers in state regulatory cases in many states for three-plus decades. He was testifying in the 2007 San Diego Gas & Electric (SDG&E) rate case that first adopted Option R rates with reduced demand charges for non-residential solar customers in California:

> *Demand charges were invented almost 100 years ago as a crude approximation of system peak costs. The individual customer's peak could be measured, even though the customer's contribution to the system peak could not be measured. The utility charged for what it could measure. Now that we are in the 21st century, with time-of-use energy meters in wide use and advanced meters coming, demand charges have outlived a significant portion of their rationale.*
>
> *High demand charges also make distributed generation (DG) more risky and less economic, as a short outage of the customer's distributed generation will result in payment of the entire demand charge. In the case of SDG&E, which is a relatively isolated load pocket, DG should be actively encouraged, not discouraged. The alternative to DG is either expensive transmission line construction or expensive construction of central station power plants in the area, or both. SDG&E can profit through increased rate base (with equity returns above the cost of capital) by building generation and transmission, can make deals with affiliates for development of generation, and has made the claim that purchased power also requires an equity cushion. However, DG serving customer loads does not have the built-in opportunity for profit, thus SDG&E has an economic incentive to discourage it. Its rate design for large customers does exactly that.*
>
> *Additionally, there is a strong rationale for avoiding the use of the blunt instrument of a demand charge. Costs in the highest peak hours are relatively high and not only for the conventional reasons shown in marginal cost analysis (high energy prices plus capacity need). There is also a relatively large block of costs that SDG&E has not included anywhere in its marginal costs; these are costs for "glue" to hold the utility system together, specifically ancillary services, ramping, and out of market and out-of-sequence*

> *purchases by the ISO. For SDG&E, many of these services are provided at high cost by inefficient gas-fired steam units. These costs are not a simple percentage of system energy costs but tend to balloon (even as a percentage of energy cost) as the system moves closer to the peak. Cost causation would suggest raising energy charges in hours close to the peak to provide incentives for demand reduction and demand response that would reduce the size of these types of costs.*[13]

Some jurisdictions are now doing exactly what Mr. Marcus recommended, replacing demand charges with volumetric TOU and CPP rates.[14] This represents a far more accurate, targeted, and cost-based means to charge customers than the traditional 15- or 30-minute maximum demand charge.

Q19: In this case, which parties are heading in the direction that TASC recommends?

A19: TASC supports the direction of the Office of the Consumer Advocate's (OCA) proposal to further develop time-of-use rates that can be made available to all customers, including customers who install DG. TASC also would not oppose a pilot program to develop an optional TOU rate that uses real-time ISO New England locational marginal energy prices as the energy component of a TOU rate, as the City of Lebanon's Mr. Below has proposed.

E. NH IOUs Do Not Have Adequate Metering for Demand Charges

Q20: Do the New Hampshire utilities have adequate metering on small customers that would make it reasonable to implement demand charges for DG customers?

A20: No, they do not. The Commission has acknowledged that the stated purpose of HB 1116 is to continue "reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation

[13] CPUC A. 07-01-047, Prepared Testimony of William B. Marcus on behalf of Utility Consumer Action Network (served August 10, 2007), at pp. 41-42.
[14] *See* CPUC Decision No. 14-12-080, referenced in Footnote 7 above.

for such locally produced power."[15] If DG customers are required to use demand charge-based rates, customers must have adequate knowledge of their monthly demand if they are to have a "reasonable opportunity" to consider an investment in renewable DG. Neither Eversource nor Unitil provides small customers with notice or data today on what their maximum monthly demand is or when it occurs. Eversource's present meters do not record 30-minute demand; Unitil's meters are capable of recording 15-minute demand, but this data is not provided to customers in any form.[16] As a result, customers would have to commit to a long-term investment in DG <u>before</u> they even could obtain the data to know what their maximum demand is, or how their monthly bill would be impacted by a demand charge-based rate. Thus, customers would be required to make long-term investments without a firm knowledge of what the economics of the investment would be. This new uncertainty would violate HB 1116 by not providing a reasonable opportunity for customer investments in renewable DG.

F. DG Customers Will Have Difficulty Understanding Demand Charges.

Q21: TASC's opening testimony discusses the problems with small customers understanding and accepting demand charges. Will these problems apply to the utilities' demand charge proposals?

A21: Yes. Bonbright's first and eighth principles emphasize that rates should be understandable, be accepted by customers, and enable customers to use energy efficiently. The utilities' demand charge proposals fail to meet these goals.

TASC's opening testimony discussed the data from several utility-conducted surveys which show that customers are confused by demand charges

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[15] DE 16-576 U, Order of Notice, "Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators," at p. 2.

[16] See Eversource and Unitil responses to Data Requests TASC 3-011 (Eversource) and TASC 3-07. These responses are included in Appendix F. Eversource's testimony (Davis), at p. 10, states that new meters capable of recording demand data will be needed to implement Eversource's proposal.

and consider them burdensome in comparison to other options. Customers lack specific demand data on typical home energy uses and appliances, which typically report annual kWh energy consumption, not the 15-minute kW demand draw. Understanding and accepting demand charges will require customers to become familiar with data on their 30- or 15-minute demands which they simply do not possess today. As discussed above, due to metering limitations, demand data from the utility will not even become available to customers until after they decide to invest in DG. In discovery, the utilities suggested that customers interested in DG could first invest in a home energy monitoring system, collect their own 15-minute data on their electric consumption, and then analyze that data to see if DG would be a sound investment under a demand-charge-based rate.[17] Obviously, the cost and complexity of such self-metering by small customers would erect a major new practical and economic barrier to adoption of renewable DG.

Even if the 15- or 30-minute demand data is available, demand charges would substantially complicate customers' and vendors' ability to analyze and project the bill savings not just from DG, but from other types of demand-side programs such as energy efficiency and demand response. Customers and vendors will have to analyze and understand much more data on customers' energy use to appreciate when their demand peaks and what the hourly profile of their usage is.[18] In contrast, it is much simpler for customers to understand TOU rates under which customers simply have to learn that energy use is more

[17] See discovery cited in Footnote 14 above. Eversource cites a home meter monitoring system costing $180 that requires monitoring via wifi and that receives mixed reviews for ease of setup and use. Unitil's response actually suggests that solar providers should supply the historical demand data that customers would need to evaluate a solar investment under three-part rates, presumably by installing third-party metering on the potential customer's home for an extended period.

[18] Today, the solar sales process can use monthly usage data, for example, from the paper bills from the last year of the potential customer's utility service. Obviously, the software exists to perform the more complex calculations using hourly load and generation profiles, but the customer is unlikely to be able to verify the math and may have much greater difficulty understanding and trusting the salesperson's estimate. The lack of demand data and the increased complexity will significantly complicate the sales process for solar and other DG technologies and negatively impact the sustainability of the DG market in New Hampshire.

expensive during certain well-defined hours of the day, a message that many utilities already convey during peak demand periods.

Finally, none of the utilities in New Hampshire have undertaken customer education or market research around demand-based rates for small customers.[19] The Commission should not consider, much less adopt, mandatory demand-based rates for DG customers until the necessary metering is in place, historical demand data is readily available to all customer classes, and the utility has provided the outreach and education required for customers to understand, accept, and take actions based on their kW demand. None of these prerequisites has been met. Even then, volumetric TOU and CPP rates will be a more accurate, cost-based, and understandable rate design for small customers.

In sum, the complex rate structures that Eversource and Unitil would impose on residential and small commercial DG customers might be appropriate for large commercial, industrial and institutional facilities whose usage dominates the circuit from which they are served. These are large, sophisticated customers who understand both their energy usage and their 15-minute demand, have the metering to track both energy use and demand in real time, and can pay facility managers dedicated to managing those demands and costs. But such a structure is not understandable or workable for residential customers who spend only a few minutes a month focused on their utility bills. Such a result would be contrary to the first Bonbright principal that rates should be simple, understandable, and broadly acceptable to customers. Imposition of mandatory demand charges on residential DG customers will establish a major barrier to the adoption of customer-sited, behind-the-meter DG and will not contribute to the sustainable growth of this important renewable resource.

[19] See discovery cited in Footnote 14 above.

Q22: Is the simplicity and understandability of the existing NEM structure a significant benefit to customers, the utility, and the Commission?

A22: Yes, it is. The simplicity and understandability of NEM for the customer is a major reason why it is now used in 44 states.[20] It is important for the Commission to recognize that, under net metering as it exists today, a customer who installs a DG system will continue to see, on the margin, exactly the same price signals from rate design that the customer would see if he or she were a non-NEM customer. This is true regardless of whether the solar customer is importing or exporting power at any moment.[21] This "transparency" of the price signals under NEM is a strong reason to continue the present structure of NEM. Customers find it easy to understand that the same signals which they receive under the regular rate design will continue unchanged if they install a net-metered solar system. This also means that the utilities, the solar industry, and the Commission do not have to educate NEM customers about rate design in any way that is different than non-NEM customers. For example, with a continuation of NEM, if a utility were to decide to encourage more customers to adopt TOU or CPP rates, informing customers about these new rate structures will be the same regardless of whether the customer has a DG system or not.

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[20] See http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2015/04/Net-Metering-Policies.pdf.

[21] For example, at my home I take service as a NEM customer under PG&E's E-6 residential TOU rate, which has three pricing periods, on-peak, part-peak, and off-peak. If I consume power from the PG&E system during the summer on-peak period of 1 p.m. to 7 p.m., I pay for that power at the high E-6 on-peak rate. My west-facing PV system at times produces more power than my home consumes during PG&E's on-peak period, and I export this power back to PG&E, which the utility then uses to serve my neighbors and for which I receive a credit at the full E-6 on-peak rate. Yet even when my system is exporting, I retain a strong incentive to shift any available loads out of the on-peak period – if I do not run appliances between 1 p.m. and 7 p.m., I send additional solar kWhs out to the grid, earning additional net metering credits at the E-6 on-peak rate. This is no different than the price signal I face when I am importing on-peak power. In the mornings, evenings, and on weekends, I pay the much lower E-6 part- or off-peak rates when I run appliances, and I also earn lower NEM credits for exports during these hours. Thus, even as a solar customer, I continue to see exactly the same TOU price signal as non-solar customers on the E-6 rate, and I continue to have the same incentive to shift my loads to part-peak or off-peak periods.

G. No States Have Adopted Mandatory Demand Charges for Residential Customers, With or Without DG.

Q23: Are you aware of any states that have mandated the use of demand-charge-based rates for all residential or small commercial customers?

A23: No, I am not. The only example that the utility witnesses can cite is from Italy, and even in that country the rates are based on the maximum delivery capacity serving a customer, not on an ongoing measurement of the customer's demand.[22] A recent utility-sponsored survey of the use of residential demand charges in the U.S. shows that there are only three small U.S. utilities – two rural cooperatives in Kansas and South Carolina and one town in Vermont – with a total of 65,000 customers which mandate three-part rates for all residential customers.[23]

Q24: Have any U.S. electric utilities required residential customers to use three-part rates with significant demand charges if they install DG?

A24: Yes, and the result is instructive. In early 2015, the Salt River Project (SRP), a publicly-owned utility and Arizona's second-largest electric utility, established a new Standard Electric Price Plan under which all new customers deploying customer-sited solar systems are required to take service using a new E-27 tariff. Although officially adopted by the SRP board in February 2015,[24] the new tariff applied retroactively to all solar customers that applied to deploy rooftop solar after December 8, 2014. Under this tariff, solar customers are subject to a range of fees that, but for the decision to install solar, would not otherwise apply, including significantly higher monthly fixed charges, as well as demand charges based on the maximum 30-minute demand in the month. Additionally, as

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[22] Unitil Testimony (Overcast Direct), at p. 25. Although residential rates in Italy have small demand charges based on the maximum interconnection capacity, they also have steeply inclining volumetric rates that recover most costs. See Toby Brown and Ahmad Faruqui, *Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs* (Brattle Group, August 2014), at pp. 18-21.

[23] Direct Testimony of Ahmad Faruqui on behalf of Arizona Public Service Company (Arizona Corporation Commission Docket No. E-01345A-16-0036), at Attachment AJF-2DR: Summary of Residential Three-Part Tariffs.

[24] As a publicly-owned utility, SRP is not regulated by the Arizona Corporation Commission.

compared to the default residential tariff that the new rate plan replaces, solar customers receive significantly lower bill credits for any excess energy sent back to the grid. SRP remains today the only utility in the U.S. with a significant number of residential solar customers that has implemented a mandatory demand charge-based rate for solar customers.

Table 1 compares SRP's current rate structure for DG customers to Eversource's and Unitil's proposed residential DG rates. SRP has a summer demand charge that is limited to the on-peak hours, whereas the New Hampshire utilities are proposing a non-coincident demand charge applicable for all months, with Eversource proposing a significantly higher non-coincident demand charge than SRP. Energy rates in New Hampshire would be higher than for SRP, but Eversource and Unitil are also proposing to reduce export credits significantly. Finally, one must remember that solar costs are lower in Arizona, and the solar resource in Arizona is the best in the U.S.

Table 1: *SRP E-27 (3-10 kW) and Eversource / Unitil Proposed DG Rates*

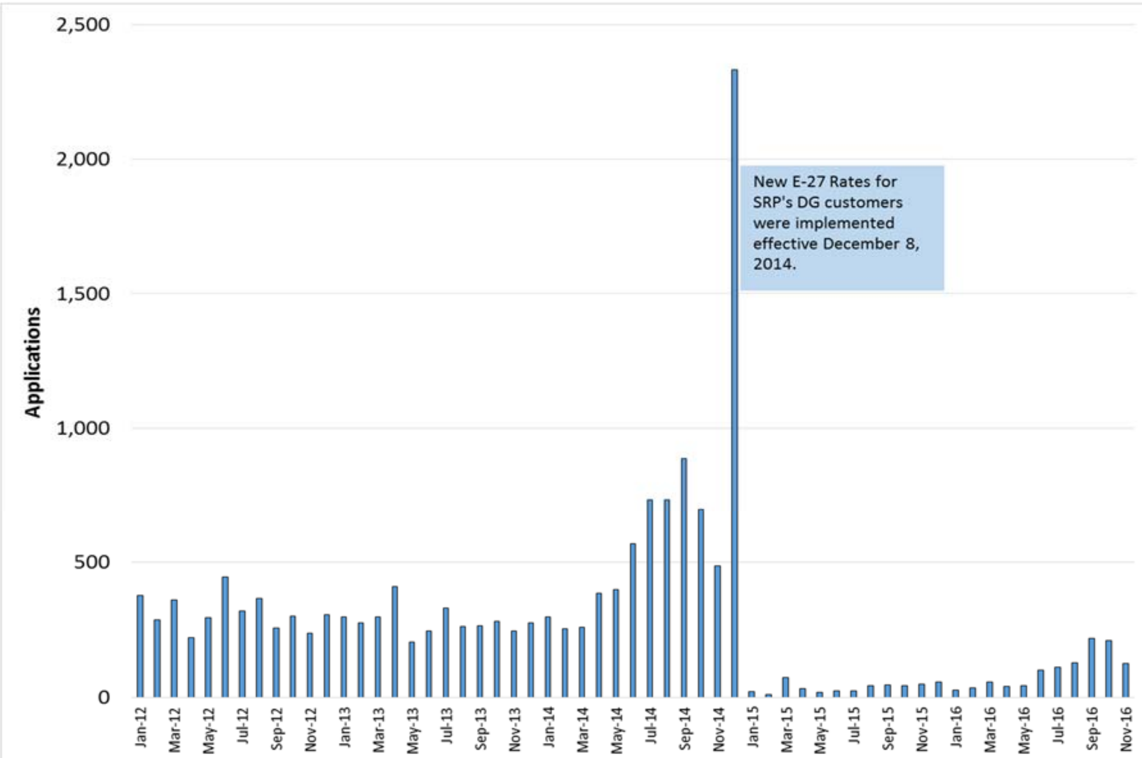
Utility	**Rate**	**Months**	**Monthly Charge** $/Month	**On-Peak Energy** $/kWh	**Off-Peak Energy** $/kWh	**Summer On-Peak Demand** $/kW	**Non-coincident Demand** $/kW
SRP	E-27	Summer Peak (Jul-Aug)	30.94	0.0633	0.0423	17.52	NA
		Summer (May-Jun/Sep-Oct)	30.94	0.0486	0.0371	14.63	NA
		Winter (Nov-Apr)	32.44	0.0430	0.0390	NA	5.46
		Imports / Exports	**Monthly Charge** $/Month	**All Energy** $/kWh			**Non-coincident Demand** $/kW
Eversource	R	Import rate	12.89	0.1143		NA	9.13
		Monthly Export credit[a]		0.0347			
Unitil	D	Import rate	15.00	0.1023		NA	5.32
		Hourly Export credit[a]		0.0347			

[a] *Export credit reflects average LMP energy price avoided by DG output in 2016.*

Q25: What has been the impact of SRP's E-27 rate on SRP's solar market since the rate was adopted?

A25: The impact of the new rate structure on the solar market in SRP's service territory has been nothing short of devastating in terms of solar adoption. Below is a figure that provides an overview of monthly solar applications from 2012 through November 2016.[25]

Figure 6: *Solar Applications in SRP Territory*



As can be seen in the figure, monthly applications declined abruptly after December 2014, indicating the profoundly adverse impacts of the new rate plan on solar economics and customer uptake. A closer look at the data shows that over 99% of applications submitted in December 2014 were submitted on or before December 8, driven by the fact that applications submitted after this date would be subject to the new tariff. Of these, 57% were actually submitted on December 8 itself. Applications fell by 93% in 2015 compared to the levels

[25] Data from www.ArizonaGoesSolar.org. The information reflected in the table includes PV applications, both residential and commercial, however, because commercial applications only represent approximately 1% of the applications over the period shown in the table below, confining this analysis to residential PV would make minimal difference in the overall results and trends observed.

reached in 2014, before recovering slightly in 2016 to 81% below 2014 levels. Thus, the solar market in SRP's territory has not recovered since the new SRP rates took effect.[26] Thus, the impact of a three-part rate structure that is similar to what Eversource and Unitil have proposed has been a major decline in the solar market in SRP's service territory. It is highly likely that a similar result would occur in New Hampshire, especially given that New Hampshire has higher solar costs and a much less favorable solar resource than Arizona.[27] This is further confirmed by the impacts of the Eversource and Unitil DG rate proposals on the bill savings that customers can realize from renewable DG, discussed later in this rebuttal.

Q26: If Unitil's and Eversource's proposed three-part rates for DG customers are approved as proposed, do you have an opinion on the impact that would have on jobs in the distributed solar installation business in New Hampshire?

A26: Yes. Based on the experience in Arizona, I expect that there would be a significant contraction in the solar industry in New Hampshire, and that solar installation companies in the state will curtail jobs and operations in New Hampshire, and, if possible, shift workers and operations to other New England states with more robust solar industries and more reasonable rate design and net metering policies.

Q27: Are you familiar with other recent proposals from large utilities in the U.S. to implement three-part rates for all residential customers or for those that install DG?

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[26] One vendor, Solar City, had more than half of the SRP market before the change in SRP's tariff. Solar City pulled out of the SRP market when the new tariff took effect. Obviously, given the 80% decline in applications, the void left by Solar City's departure has not been filled by the numerous other solar vendors operating in Arizona.

[27] Current LBNL data on residential solar costs show median 2015 prices of $3.40 per watt in Arizona and $3.60 per watt in New Hampshire. Solar capacity factors are about 15% in New Hampshire, versus 20% in Arizona, per NREL PVWATTS data

A27: Yes, I am, and I have participated directly in most of these cases. I have summarized the outcomes of these cases in Appendix E to this rebuttal. Please note that, in addition to proposals to implement three-part rates, there have also been several proposals to adopt tiered fixed monthly charges, with the tiers scaled to various measures of residential customer demand or energy usage. I would characterize these as "proto-demand charges." The utilities that have proposed such tiered fixed charges generally lack the metering to implement 15- or 30-minute demand charges, but have justified the tiered fixed charges as a first step toward demand charges until the necessary advanced metering infrastructure can be installed. These cases are also listed in Appendix E. Generally, state commissions have not mandated three-part rates or proto-demand charges, either for all residential customers or for those that install DG, although some commissions have authorized optional three-part residential rates as a standard offering (Arizona) or on a pilot basis (Colorado).

H. Demand Charges Would Unreasonably Reduce DG Bill Savings.

Q28: Have you calculated the reduction in the bill savings that would be available to DG customers if the Eversource and Unitil demand charge-based rates are adopted?

A28: Yes, I have. **Table 4** below compares the change in bill savings for many of the proposals in this docket. The analysis also includes the impacts of the proposed changes in export credits that are discussed in the next section of this testimony. The table shows that the Eversource and Unitil demand charge proposals plus their reductions in export credits have by far the largest impacts on bill savings, reducing them by 50% to 60% for a typical DG customer. Bill savings are a principal benefit that DG customers realize from their systems and a major means by which they are able to make economic investments in DG resources. Such a large reduction in bill savings would undermine the stated goal of HB 1116 for

New Hampshire to continue to offer reasonable opportunities for customers to invest in DG resources.

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III. REDUCTIONS IN THE EXPORT RATE

A. TASC Supports Removing Public Benefit Charges.

Q29: Many of the parties to this docket suggest that specific charges that recover the costs of public benefit programs, such as the public benefit charges and the electricity consumption tax, should be removed from the credit that NEM customers receive for their exported power, when the meter runs backward.[28] Does TASC support this change?

A29: Yes. This step would bill all customers for these public benefit charges on the same basis – on the amount of power which is delivered to them from the electric system. This would ensure that all customers contribute to these important public purpose programs on the same, equitable basis of amount of electric energy which they use from the utility system.

Q30: Did TASC's analysis assume that these public benefit charges and taxes are removed from the export credit?

A30: No, it did not. Removing these costs from the export rate would decrease the cost of NEM by about $0.005 per kWh on a 25-year levelized basis for Eversource customers, assuming that small customers export 40% of their power.

B. Benefits of Exports Are Not Limited to Avoided Generation Costs

Q31: Liberty has proposed to limit the DG export rate simply to the default energy charge.[29] Does this fully capture the benefits of DG?

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[28] The utility proposals discussed below would all eliminate these charges from the export rate, as would the OCA DG TOU Rate and Fixed Credit Rate proposals, which would collect these charges on the basis of gross loads before any DG output. See OCA testimony (Huber), at pp. 22-23. The New Hampshire Sustainable Energy Association (NHSEA) supports removing the system benefit charge, the stranded cost recovery charge, and the electricity consumption tax from the export credit; see NHSEA testimony (Epsen), at p. 12 of 17. The Conservation Law Foundation (CLF) supports removing the system benefit charge from the export rate; see CLF testimony (Chernick), at pp. 27-28.

[29] Liberty testimony (Tebbetts), at p. 4 of 25.

A31: No, it does not. The essence of distributed generation is that it consists of large numbers of small generation facilities located behind the meter, widely distributed across the utility's service territory, and interconnected to the distribution system. At today's relatively low penetration of DG, the power produced in DG facilities is either consumed on-site by the host customer or by one of the host's neighbors. Thus, DG does not use, and avoids the long-term costs for, the transmission system and the upstream, higher voltage distribution system. This essential benefit of DG means that the credit for exported power should include avoided delivery costs as well as generation costs. The benefits of distributed generation should be calculated considering the marginal costs of all components of the grid services that are required to serve a customer at its end use meter – generation, transmission, and distribution.

Q32: The utilities argue that DG is unlikely to reduce distribution costs, and that adequate and economic DG capacity is unlikely to be available when and where it is needed to defer specific distribution upgrade projects.[30] Please respond to these arguments.

A32: Today, the primary impact of the development of DG, like other demand-side resources, is to reduce the overall level of the utilities' loads. Over the long-run, these reductions in demand will reduce the distribution investments that the utilities must make. The most accurate measure of these avoided costs is the utility's long-run marginal cost for distribution, which can be calculated using a regression of distribution investments as a function of load growth.[31] This effectively separates that portion of overall distribution investments that are driven by load growth from those that are pursued for other reasons, such as reliability, replacement, or grid modernization.[32] The important point here is that,

[30] See, for example, Eversource testimony (Labrecque & Johnson), at pp. 23-27, also Unitil testimony (Meissner), at pp. 35-36.

[31] Libety and Unitil calculate their marginal distribution costs using exactly such an approach.

[32] It is important to recognize that distribution investments can have a variety of benefits, and it is often inaccurate to say that a particular distribution project is only being pursued for reliability, for example. A new substation can provide benefits from added load-serving capacity even if its principal justification is

just because it may be impractical or unlikely today for DG alone to avoid distribution investments does not mean that DG has zero distribution capacity benefits. Customer-sited DG combines with other customer investments in energy efficiency (EE) and demand response (DR) to produce substantially slower long-term load growth on the distribution system, resulting in long-run avoided distribution costs from reduced utility investments in distribution infrastructure. These distribution benefits are measured by the utility's long-run marginal cost of distribution capacity. Solar PV's share of these benefits is determined by the load match factors that TASC has calculated which measure solar DG's ability to reduce the peak distribution loads that drive load-related distribution investments.

These benefits are largely counterfactual and invisible; in other words, they result from the long-term demand trajectory of the utility being significantly lower as a result of demand-side EE, DR, and DG resources than a "business as usual" trajectory. Such counterfactual benefits will rarely show up publicly, or even in utility rate cases, as DG (or DR or EE) replacing or deferring a specific distribution investment. Instead, the utility planning process will respond over time to a lower level of demand resulting from demand-side resources by needing to build less infrastructure. For this reason, it is not fair or reasonable for the utilities to argue that it is impractical or uneconomic for DG alone to defer a specific recent distribution project.[33]

Q33: But aren't the distribution benefits of DG and other demand-side resources location-specific?

A33: Yes, they are, but this is not a reason to assign them an overall value of zero until they can be assessed on a location-specific basis. Instead, the more accurate and

reliability or replacement of aging equipment. The converse is also true: a new substation built due to load growth is also an opportunity to improve reliability and to modernize the grid. Eversource's witnesses recognize that distribution projects often have such multiple benefits. See Eversource testimony ((Labrecque & Johnson), at p. 24.

[33] See, e.g. Unitil's testimony (Meissner), at pp. 35-36.

equitable approach is to assess these benefits now on an overall "system" basis, as TASC has done, and then to proceed in the future, as DG penetration grows, to develop a more location-specific assessment of avoided distribution costs. States such as California and New York are taking steps in this direction, with California's Distribution Resource Plans and New York's REV process.

Q34: Eversource and Unitil both propose to reduce the export credit to compensation at the locational marginal price in the ISO-New England energy market.[34] What are the problems with this proposal to reduce export credits?

A34: Renewable DG are long-term resources, with benefits that are substantially greater than avoiding short-run energy costs. TASC's opening testimony quantified these long-term benefits, which include avoided costs for generation and delivery capacity, line losses, fuel hedging benefits, and market price mitigation (DRIPE) – all of which are direct benefits for ratepayers. Like the Liberty proposal to limit the export credit to the default supply rate, setting the export credit at short-run LMPs fails to recognize that DG avoids T&D costs, because the power is delivered to customers without using upstream T&D capacity, making more delivery capacity available for load growth. Finally, export compensation based on short-run energy market prices does not provide the certainty necessary to support customers' long-term investments in DG facilities.

Q35: Unitil proposes to end the month-to-month carryover of NEM credits.[35] Should there be an issue with such carryovers?

A35: No. The only possible issue with monthly carryovers is if NEM credits are carried over from one month to another on a kWh basis instead of a dollar basis. If carryovers occur as kWh, and the retail rate is a seasonal or TOU rate, a winter

[34] See Eversource testimony (Davis), at pp. 5 and 6 of 10. Cite.
[35] Unitil Testimony (Overcast Direct), at p. 28.

or off-peak kWh NEM credit generated in one month can possibly offset a more valuable summer or on-peak kWh credit in a subsequent month, or vice versa.[36] This can be easily remedied by providing that NEM credits are carried over on a dollar basis. This is how NEM carryovers are administered in California and Colorado. California has adopted mandatory TOU rates for commercial customers, and is moving toward the use of TOU rates as the default rate structure for residential customers.[37] Pacific Gas & Electric, which has the most net metering customers of any U.S. utility, has achieved a high penetration of residential solar customers on TOU rates (over 30%) using the rollover of excess energy credits on a dollar basis. I am not aware of any problems with customer acceptance of this approach; indeed, at my home I personally have been a satisfied net metering customer of PG&E on a TOU rate for the past 13 years.

C. OCA's DG TOU Rate Is Flawed in Two Respects.

Q36: The Office of the Consumer Advocate's (OCA) testimony includes a "DG TOU Rate" proposal applicable to DG and battery storage customers.[38] Please comment on this proposal.

A36: I support the direction of OCA's TOU Rate proposal to encourage DG customers, and other residential customers as well, to use volumetric TOU rates. TOU structures will align rates more closely with the higher capacity-related costs that the utility incurs during the time periods of peak usage of the grid. I also support OCA's proposal to limit the on-peak period to a narrower set of afternoon hours than the utilities' current residential TOU rates.

Q37: Are there elements of the OCA DG TOU Rate proposal that are not reasonable?

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36 With flat rates, the value of an export credit is the same in every month, so there is no issue with a mismatch of the value of carried-over NEM credits.

37 See, generally, California Public Utilities Commission Decision No. 15-07-001 (issued July 3, 2015).

38 OCA Testimony (Huber), at pp. 17-32.

A37: Yes. The Commission should not adopt OCA's proposed export charge and its "partially non-bypassable" transmission charge.

Export Rate. OCA would levy a charge on exports to the grid that is "intended to appropriately recover the fixed costs associated with the portion of the utility-owned distribution grid accessed by DG customers when energy from DG systems is being exported."[39] The export charge is flawed for the following reasons:

- DG customers simply do not use or "access" the grid to deliver exports. It is the utility that delivers those exports and that is compensated for providing that service. When exported DG power passes the DG customer's meter, it becomes the responsibility of the utility to deliver that power to the neighboring customers. Those neighbors fully compensate the utility for providing that delivery service when their meters run forward to use the DG exports. OCA admitted this in discovery.[40] To charge the DG customer for delivering exported power amounts to billing them for a service which they are not receiving.

- DG customers already pay to have adequate grid capacity to accept their exported power, via the interconnection process. To require a DG customer who may have paid once for a system upgrade necessary to allow exports to pay again for "access" to the same delivery system through an export charge would amount to double-billing such DG customers.

- Even if OCA's rationale for an export rate was sound, its methodology to calculate the export charge is flawed and nonsensical. OCA's witness Mr. Huber says that the export rate should collect secondary distribution costs, which he estimates as "~$0.02 per kWh for a typical New Hampshire utility" for service to a regular, non-DG residential customer.[41] He then sets the export rate at double this amount ("~$0.04 per kWh'), on the grounds that DG customers export just 50% of their power. However, the stated purpose of the OCA's export rate is to collect costs associated just

[39] *Ibid*., at p. 25.
[40] See OCA response to TASC 1-9(e), included in Exhibit F.
[41] OCA Testimony (Huber), at pp.26-27.

with exports.[42] Doubling the rate means that DG customers would pay twice the rate for access to the secondary distribution system as regular customers, for each kWh that is actually placed on that system. Finally, only DG customers with relatively large systems that produce close to the customer's annual usage export as much as 50% of their power. A residential DG customer with a smaller system relative to their usage might export only 10% of their power, for example. Under the logic of OCA's export rate, such a customer with 10% exports should pay an export rate of ten times "~$0.02 per kWh," or "~$0.20 per kWh," which clearly would be punitive for a customer who exports so little power.

- OCA stated in discovery that the purpose of the export rate is to require DG customers "to pay for their access of the distribution system to essentially store their exported electrons."[43] As TASC explained in its opening testimony, as a matter of basic physics, exported electrons are not in any way stored in the electric grid in a NEM transaction. The crediting of NEM exports is simply an accounting mechanism to offset the value of exported power at the time it is exported against the cost of imported power at a different time. There is no physical capacity of the system needed to do this accounting, which under standard NEM is performed simply by the meter turning either forward or backward depending on which way the power is flowing.

"Partially non-bypassable" transmission charge. OCA's "partially non-bypassable" transmission rate is based on a calculation that a DG customer whose system can serve 100% of its load can avoid 50% of the transmission costs that would otherwise be assigned to the customer absent DG. As a result, OCA proposes that the remaining 50% of transmission costs should be collected from solar customers as a non-bypassable charge (NBC), based on their gross load. The essential problem with OCA's position is that it focuses on just one rate element, transmission. The transmission costs that DG can avoid may be less than 100% of the transmission rate, but DG can avoid more than 100% of another

[42] Mr. Huber clearly states on p. that "[t]he export charge is intended to appropriately recover the fixed costs associated with the portion of the utility-owned distribution grid accessed by DG customers when energy from DG systems is being exported."
[43] See OCA response to TASC 1-9(d), included in Exhibit F.

rate component – generation – especially if one considers factors such as DRIPE and the reduction in fuel price uncertainty that both provide long-term reductions in generation costs. It is unfair of OCA to cherry-pick one rate element (transmission) where avoided costs are less than the retail rate, without an offsetting adjustment for another element (generation) where long-run avoided costs are higher than the retail rate.

Q38: Please address OCA's proposal to charge NBCs on the basis of gross load.

A38: I completely disagree with OCA's witness Huber that New Hampshire law requires NBCs to be collected on the basis of gross loads.[44] OCA does not point to any particular language in the statute that supports their proposal to base collection of NBCs on a DG customer's gross load. Such an assertion lacks specific support and cuts against the reality of how customers interact with the grid. First, DG customers are in no way "bypassing" the electric system: they are interconnected to the grid and continue to be significant customers of the utility. They are just smaller customers than before installing DG. Other customers who reduce their usage through other types of demand-side programs, or who simply use less than they have historically, are not considered to have bypassed the grid. Nor should DG customers be so labeled.

Charging NBCs based on gross load would assess these costs for load which is not served from the grid, and thus essentially would charge customers for what is in fact a reduction in demand from the grid. NBCs are not charged to load reductions from other types of demand-side resources such as energy efficiency. NBCs should not be charged to loads served on private property using power that never flows onto the grid. Instead, it is equitable for all types of customers to pay NBCs based on the deliveries which they take from the grid, that is, based on their use of the electric system to import power.

[44] OCA Testimony (Huber), at pp.26-27.

D. Reduced Export Rates Greatly Complicate NEM Rates

Q39: Please comment on the complexity of the utility and OCA proposals that involve export rates significantly different than the retail rate that applies to imports.

A39: Bonbright's first principle emphasizes that rates should exhibit the "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application. The complex rate structures that Eversource, Unitil, and OCA propose for the new NEM tariff would fail to meet this principle. The problem with the Eversource and Unitil rates can be seen by comparing the price signals that a NEM customer will face under both (1) continued full retail NEM and (2) the Eversource / Unitil rate structure with low rates for exported energy and non-coincident demand charges.

- **Continued full retail NEM.** As noted above, with a continuation of NEM at the full retail rate, a solar customer will continue to see exactly the same price signals that they received before solar installation. For example, under volumetric TOU rates, a DG customer under full retail NEM would see the same TOU price signal to shift load as a regular non-NEM customer. Thus, educating customers about TOU rates will be equally effective and important for all customers, both those who install DG and those who do not.

- The **Eversource / Unitil structure** of low export rates and non-coincident demand charges means that the value of customer-generated power can swing from 11 cents/kWh (the volumetric retail rate) to 3 cents/kWh (the LMP) from hour to hour, depending on whether the DG customer is importing or exporting power. As a result, a DG customer will have difficulty assessing what the marginal value of reducing or shifting his energy use will be. The complexity of significantly varying rates for imports vs. exports will be exacerbated by the fact that the customer also would have to try to manage a non-coincident demand charge applicable to the premise's maximum usage in any 15- or 30-minute period.

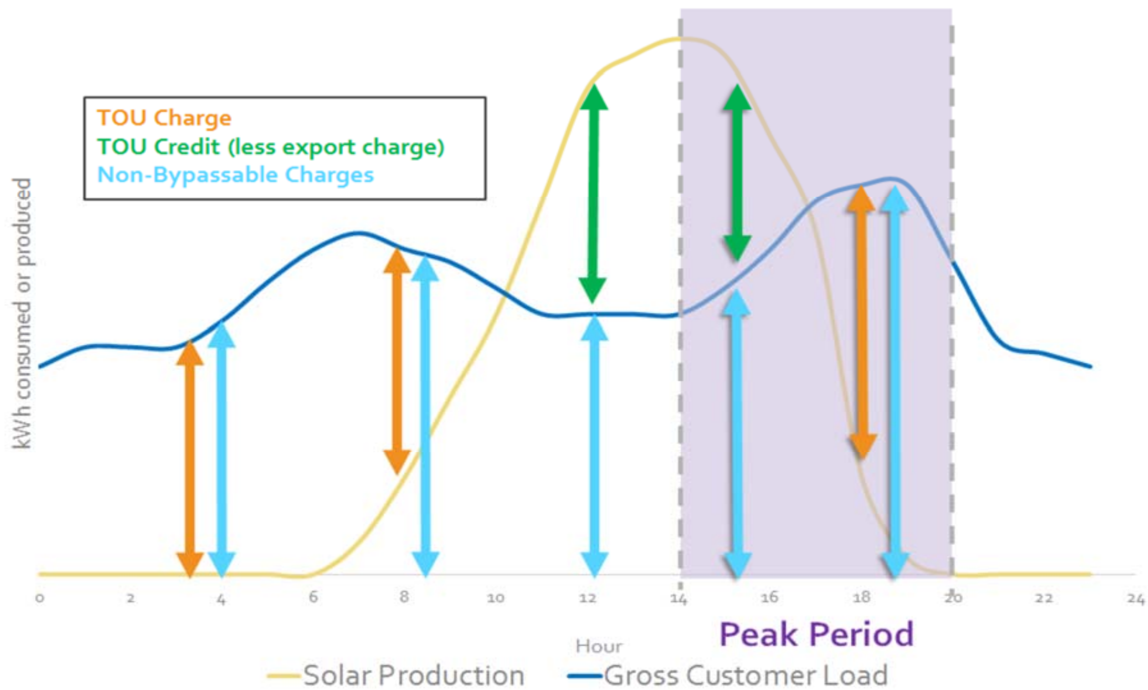
OCA's DG TOU rate suffers from a similar problem with complexity. This is well illustrated in Mr. Huber's Chart 1, reproduced below as **Figure 7**, which shows that a DG customer under the OCA DG TOU rate would have to be aware of at least six different charges that would apply at different times and to different types of kWh consumption or production.[45] These different charges and types of kWh are listed in **Table 2**. It will not be easy for a residential customer to understand and to analyze all of the different ways in which OCA's proposal would impact the customer's bill. OCA's TOU rate proposal would be greatly simplified by, first, removing the unwarranted export charge so that both imports and exports would have the same value and, second, by removing 50% of transmission as a non-bypassable charge and assessing NBCs on the basis of delivered loads, not gross loads.

Table 2: *OCA's Complex DG TOU Rate*

Distinct Charges	**Each applies to a different quantity…**
On-peak TOU Rate	On-peak (2p-8p) imports
On-peak TOU Rate less Export Charge	On-peak exports
Off-peak TOU Rate	Off-peak imports
Off-peak TOU Rate less Export Charge	Off-peak exports
Non-bypassable charges (NBCs)	Gross load (imports plus PV used on-site)
50% of transmission not in the NBCs	Net load (imports less exports)

45 The chart shows three different types of charges (colored arrows) in two different time periods (purple or white background), for six different combinations of charges and TOU periods.

Figure 7: *OCA's Chart 1*



These complex rate structures might be appropriate for large commercial, industrial and institutional customers, but they are not practical or workable for residential or small commercial customers who have limited time and attention to focus on their utility bills. Imposing such rate structures on NEM customers would erect a significant new barrier – excess complexity – to the adoption of behind-the-meter DG.

IV. OCA'S FIXED CREDIT RATE

A. The Importance of Certainty in DG Compensation

Q40: Please describe OCA's proposed Fixed Credit Rate.

A40: OCA's witness Mr. Huber also proposes the option of a Fixed Credit Rate that would apply to the entire output of a DG system. This would be a delivery rate that is fixed for a 20-year term, would be additive to the default supply charge plus a REC value, and would produce a total credit that OCA asserts is "economically viable" for solar PV in New Hampshire.[46] OCA has proposed a schedule of Fixed Credit Rates which decreases according to a pre-set series of steps, with each step corresponding to a certain amount of DG capacity. The scheduled drops in the Fixed Credit Rate are supposed to track the expected decreases in the cost of solar PV. A total of 200 MW of DG capacity would be available under this option.

Q41: Has Mr. Huber proposed a similar option in other states?

A41: Yes. Mr. Huber presented a very similar "RPS Credit" proposal in recent rate cases in Arizona for Tucson Electric Power (TEP)[47] and UNSE Electric (UNSE).[48] His proposals were made on behalf of the Residential Utility Consumers Office (RUCO), OCA's equivalent agency in Arizona.

Q42: Are there positive features of the Fixed Credit Rate concept?

A42: Yes. The concept has two important positive features: first, the delivery credit for DG output is a long-term, 20-year credit, with a term that is comparable to the life of a DG system; and, second, the credit is fixed for the full 20-year term and thus provides certainty to the DG customer. Long-term certainty is always important for prospective DG customers to be able to evaluate the economics of a DG investment. Although Mr. Huber's testimony is not clear on this point, he appears also to propose a fixed credit of $0.03 per kWh for transferring the REC to the utility.

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[46] OCA Testimony (Huber), at pp. 40-41.
[47] Docket No. E-01933A-15-0322, RUCO, Direct Testimony of Lon Huber, at pp. 33-34 and 41-43, also Surrebuttal Testimony of Lon Huber, at pp. 7-12.
[48] Docket No. E-04204A-15-0142, RUCO's Exceptions to Recommended Opinion and Order, at pp. 1-4.

B. A Fixed Credit Rate Should Apply to Either Exports or All Output.

Q43: Would you suggest any modifications to the proposed Fixed Credit Rate?

A43: Yes. The Fixed Credit Rate should apply either (1) to all of a DG customer's output or (2) just to the DG customer's exports, at the customer's option. In Arizona, RUCO agreed to modify its RPS Credit proposal to provide this option, and OCA's testimony indicates its openness to consider such an option in New Hampshire.[49] This option is necessary in order to respect a customer's right to self-consume. This right is embodied in FERC's PURPA requirements, which provide that a QF has the option to sell to the interconnected utility either its entire output or just the excess energy after the QF serves the host load, at the QF's election.[50] Finally, a Fixed Credit Rate that is available for exports alone also would simplify metering, as no second production meter would be needed unless the DG customer wants to claim or to sell the RECs for its full output.

C. OCA's Fixed Credit Rate Should Be Modified.

Q44: Please comment on how OCA has assembled the Fixed Credit Rate as the sum of an assumed default supply rate, a REC value of $0.03 per kWh, and a fixed delivery rate.

A44: Generally, the overall level of OCA's proposed Fixed Credit rates – starting at a total of $0.17 per kWh – is not unreasonable. However, the OCA proposal appears to require the DG customer to transfer the RECs to the utility at $0.03 per kWh if the fixed credit is to support economically viable solar DG. This may present a barrier for corporate and individual customers who want to retain and retire the REC. The Fixed Credit Rate option will not be economic for customers who wish to retain the REC. In contrast, TASC's analysis shows that NEM is

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[49] OCA Testimony (Huber), at p. 37.
[50] See 18 CFR §292.303(a), which requires an electric utility to purchase "any energy and capacity which is made available from a qualifying facility." It is the QF, not the utility, that decides how much energy and capacity to make available for sale to the grid.

economic even if the customer retains the REC. OCA's fixed delivery rate should be increased so that the Fixed Credit Rate option is economic even if the customer retains the REC.

Q45: Do you have concerns with the stepdowns in the Fixed Credit Rate over time?

A45: Yes. These decreases in the Fixed Credit Rate should be linked more realistically to actual PV cost reductions. Data is available on solar capital costs from regular surveys such as LBNL's annual *Tracking the Sun* publication or the reports from Greentech Media.[51] TASC suggests that recent PV price data from a recent year (for example, 2015) can be combined with recent year-over-year changes in PV prices (for example, from 2014 to 2015) to give a reasonable forecast of PV prices in 2016 and 2017. Such data also could be combined with reputable industry forecasts of PV prices. TAC does not recommend a simplistic assumption that historical price declines of 8% to 10% per year can be sustained in the future.

V. REC VALUE

Q46: What did TASC's benefit/cost analysis assume for the disposition of the RECs that renewable DG facilities produce?

A46: TASC assumed that the customer retains the REC, and did not assign a value to avoided RPS costs.

Q47: Do the RECs from renewable DG in New Hampshire have a significant value to all ratepayers, even if the REC is not transferred to the utility?

A47: Yes. DG RECs provide significant value to all ratepayers even if the REC remains with the DG customer. This is because DG reduces utility sales, thus

[51] See, for example, the most recent LBNL *Tracking the Sun IX* report at https://emp.lbl.gov/publications/tracking-sun-ix-installed-price.

lowering the utility's RPS obligation by the RPS percentage requirement times the DG output. So, for example, based on the long-term RPS requirement, which increases to 24.8% of sales by 2025 and the current Alternative Compliance Payment of $55.72 per MWh,[52] the long-term avoided RPS costs for all ratepayers of a MWh of DG which reduces utility sales and the RPS requirement is about $14 per MWh.

Q48: Did TASC include this benefit in the cost-effectiveness tests in its opening testimony?

A48: No, I did not. The impacts of this additional RPS benefit on the *Standard Practice Manual* (SPM) benefit-cost tests for the residential market can be seen in the revised results presented in **Table 3** below.

Q49: Could the RPS benefits be even larger than just those that result from reduced utility sales?

A49: Yes. Today, the RECs from DG solar are transferred to the utility if the DG customer has not been certified and registered for the production of RECs. Transfer of these unclaimed RECs to the utility provides substantial additional value to the utility and other ratepayers.

Q50: Does TASC support the testimony of NHSEA on the need to provide more efficient and transparent means for small customers to realize their REC value?

A50: Yes.

VI. UPDATED SPM COST-EFFECTIVENESS RESULTS

[52] See the details of the New Hampshire RPS at http://programs.dsireusa.org/system/program/detail/2523.

Q51: Can you provide the key results for your SPM test results assuming that (1) public benefit charges and consumption taxes are removed from the export rate, and (2) the utilities' RPS costs are reduced as a result of lower sales resulting from DG customers' systems?

A51: Yes, these results are provided in **Table 3** below, which is an updated version of Table D-17 from TASC's opening testimony, for the residential market. They provide further support for the retention of net metering with the changes that TASC has proposed.

Table 3: *Standard Practice Manual Test Results (Revised Table D-17)*

Cost or SPM Test	Utilities		
	Eversource	**Liberty**	**Unitil**
Residential	*53%*	*74%*	*73%*
Costs *(25-year levelized cents/kWh)*			
A1. Direct Avoided Cost Benefits	22.0	21.4	21.0
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	17.6	18.3	16.3
C. Bill Savings / Lost Revenues	19.6	18.7	19.0
SPM Test Results			
TRC – A1 ÷ B	**1.25**	**1.17**	**1.29**
Societal – (A1+A2) ÷ B	**1.81**	**1.71**	**1.88**
Participant – C ÷ B	**1.11**	**1.02**	**1.16**
RIM – A1 ÷ C	**1.12**	**1.14**	**1.11**

VII. NEM PROCESS / UPDATING / ADMINISTRATION ISSUES

Q52: Unitil witness Meissner suggests, on pages 46 through 47 of his direct testimony, that the additional 50 megawatts of capacity under the net metering cap established by HB 1116 should be available to prospective customer-generators "until such time as alternative net metering tariffs approved by the Commission become available." Do you agree with this process for introducing a new alternative net metering tariff?

A52: Not necessarily. TASC's position in this proceeding is that prospective net metering customers should have the ability to take part in the existing net metering program until a utility has received sufficient applications—and ultimately entered into interconnection agreements with those applicants—to reach its net metering capacity allotment, including the additional 50 MW added by HB 1116. If a new alternative net metering tariff is made available at the conclusion of this proceeding, that tariff should be offered alongside the existing net metering tariff and should only become the exclusive option when the current net metering cap is met. I continue to believe that a new alternative net metering tariff should be subject to periodic review to assess the costs and benefits of that program, but should ultimately be uncapped.

VIII. SUMMARY AND CONCLUSION – COMPARING THE IMPACTS OF PARTIES' PROPOSALS

Q53: Have you analyzed the impacts of other parties' net metering proposals on the bill savings that customers can realize from installing solar DG?

A53: Yes, and these results are shown in **Table 4** below, for residential customers.

Table 4: *Summary of Party Proposals vs. Standard NEM: Change in Bill Savings*

Proposal	Solar Output as % of Customer Load			
	50%	65%	80%	95%
OCA/DG TOU – for Eversource	-27%	-31	-34%	-35%
OCA/Fixed Credit – REC remains with customer	-18%	-18%	-18%	-18%
Eversource	-51%	-48%	-47%	-47%
Liberty	-18%	-22%	-24%	-26%
Unitil	-60%	-61%	-62%	-63%

The Unitil and Eversource proposals would have substantial negative impacts on the bill savings available to solar customers in New Hampshire. The Liberty proposal to limit the export rate to the default supply charge also would reduce bill savings significantly, by about 25% for an average DG customer who offsets 80% or more of their usage. These proposals would all result in unfavorable economics for prospective DG customers, as measured by the Participant Test, and thus would fail to comply with HB 1116's goal of ensuring that customers continue to have reasonable opportunities to invest in renewable DG. OCA's proposals also have adverse impacts on bill savings, but these could be mitigated by the changes to those proposals which I have discussed above.

Q54: Does this complete your prepared rebuttal testimony?

A54: Yes, it does.