THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISISON

DE 22-060

ELECTRIC DISTRIBUTION UTILITIES

Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

Community Power Coalition of New Hampshire

<u>Direct Testimony of Clifton C. Below</u>

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I. Introduction

Q. Please state your name, business address, and position with regard to the docket.

A. My name is Clifton C. Below and my office address is 1 Court Street, Suite 300, Lebanon, NH 03766. I am Chair of the Board of Directors of the Community Power Coalition of New Hampshire ("CPCNH" or the "Coalition''), which was granted intervenor status in this docket.

Q. Please describe your background and experience with regard electric utility regulation and energy policy.

A. I graduated from Dartmouth College in 1980 with distinction in my major of Geography and Environmental Studies. My course work included New England Energy Futures, Environmental Systems, Environmental Policy Formulation, and engineering courses in Community Systems (e.g. electric and water utilities) and Principles of Systems Design. In 1985, I earned an M.S. in Community Economic Development from Southern NH University, with course work in such areas as accounting, financial and organizational management, financing, and business development. During this time, I became a partner in the development of two commercial buildings on urban renewal parcels that helped to revitalize downtown Lebanon. I continue to operate and manage one of those two buildings that enabled me to begin serving in the New Hampshire legislature for 12 years starting in 1992 and do this volunteer work on behalf of CPCNH.

At the start of my first term in 1992, I was appointed to the House Science Technology and Energy (ST&E) Committee. The first study committee that I was appointed to was the "Small Power Producers and PSNH Renegotiations Legislative Oversight Committee" that gave me a crash course into LEEPA and PURPA issues, as well as the tension between competition and regulation, as over-market contracts with independent power producers (also known as qualifying facilities or QFs) were being renegotiated. Those contracts and the PUC rate order approving them were originally justified by the same load and rate projections that were used to justify continued investment in the Seabrook nuclear station.

In 1995, I Chaired the Policy Principles, Social and Environmental Issues Subcommittee of the Retail Wheeling and Restructuring Study Committee. In that role, I worked closely and collaboratively with then ST&E Chair Rep. Jeb Bradley and many other legislators and stakeholders to craft a consensus report and recommendations that became the foundation for NH's Electric Utility Restructuring statute, RSA 374-F, the enactment of which enjoyed broad bipartisan support and was the first such statute in the nation to call for customer choice in generation supply. In 1996, Rep. Bradley and I provided joint written and in-person testimony before the Energy & Power Subcommittee of the U.S. House Committee on Commerce on State and Federal issues related to electric utility restructuring on behalf of the NH House of Representatives. In 1997 I sponsored HB 485 with my co-sponsor Rep. Bradley that reformed the NH LEEPA statute, RSA 362-A, and first established net energy metering in New Hampshire in 1998.

After I was elected to the New Hampshire State Senate in 1998, I was approached by Attorney Tom Rath and the CEO of Northeast Utilities (NU, owner of PSNH, now Eversource) and was asked to be the prime sponsor of (then, controversial) securitization legislation that NU saw as critical to resolving PSNH's litigation against NH's electric utility restructuring. I did so, and in 2000, I was part of the team that negotiated a resolution of PSNH's litigation with the enactment of RSA 369-B with strong bipartisan support that enabled restructuring to proceed in New Hampshire. Throughout my 12-year tenure in the legislature, I always served on the policy committees that dealt with energy and electric utility issues and became active in regional and national forums. For example, from 1997-2004, I served on the Advisory Council on Energy of the National Conference of State Legislatures (NCSL), including 3 years as Chair and the Energy & Electric Utilities Committee, Assembly on Federal Issues, where, as Chair in 2000-2001, I facilitated a consensus based comprehensive update of NCSL's National Energy Policy (and other policies) used for lobbying the federal government on behalf of all state legislatures. I testified before the United States Senate Committee on Energy and Natural Resources on "Electric Industry Restructuring," with a particular focus on transmission issues, on behalf of NCSL. I also served as a member of the National Council on Electricity Policy, Steering Committee from 2001-2004.

After declining to seek reelection to the State Senate, Governor Lynch nominated me to the NHPUC, where from the end of 2005 into 2012 I served as a Commissioner. As Commissioner, I read reams of testimony, participated in examination of witnesses and the adjudication of some 360 cases with public hearings. I was active in ISO New England stakeholder processes and other regional and national forums on behalf of the NHPUC and the State. I served on the National Association of Regulatory Utility Commissioners (NARUC) Energy Resources & Environment Committee for 6 years including 3 as a Vice-Chair. I also served on the FERC-NARUC Smart Grid and Demand Response Collaborative, 2008-2011; and on the Electric Power Research Institute (EPRI) Advisory Council, 2009-2011; and its Energy Efficiency/Smart Grid Public Advisory Group, 2008-2010. I also served as President of the New England Conference of Public Utility Commissioners (NECPUC) from 9/2010 to 9/2011 during which time I was involved in early advocacy for "pay for performance" for winter capacity payments including the enablement of aggregated retail demand response programs participating in the ISO-NE markets as states had not yet enabled distributed energy resources to be able to respond to temporal price signals in the federal wholesale electricity market.

I provided direct, rebuttal, and live testimony in DE 16-576, the net metering docket that developed alternative net energy metering tariffs (which I refer to as NEM 2.0, with NH's original net metering referred to NEM 1.0, and any revised tariffs coming out of this docket referred to as NEM 3.0). The City of Lebanon had also proposed a time-based NEM compensation pilot in collaboration with Liberty Utilities in that docket, which the Commission conceptually approved, but in the end, it was not feasible due to metering constraints and requirements in RSA 53-E, through which we were planning to operate the pilot as an "opt-in" municipal aggregation. Subsequently, I turned my focus to updating RSA 53-E and establishing the Community Power Coalition of New Hampshire with other communities. I have added additional relevant background and experience as Attachment 1. For convenient reference, I have also attached an annotated version of NH's net metering statute and related definitions and statutory purpose statement, a version of which I shared with DE 22-060 stakeholders last winter as Attachment 2.

II. Overview of Issues

Q. What is the Community Power Coalition of New Hampshire's interest in future net metering tariffs?

A. The Coalition is a joint powers agency of 48 NH municipalities and one county, with membership growing every month.[1] Our current members comprise about 30% of the state's population. CPCNH currently serves ~80,000 electric customers in 14 community power aggregations (CPAs) with expectations to launch all current members by 2025. We are the 3rd largest supplier of electricity in NH by customer count and we will soon be the 2nd largest supplier after Eversource default service. As an alternative default service supplier to the distribution utilities (RSA 374-F:2, I-a), the members of CPCNH want CPCNH to offer net metering rates and programs, pursuant to our adopted community electric aggregation plans (EAPs). RSA 53-E:6, III(f) requires EAPs to detail "[h]ow net metered electricity exported to the distribution grid by program participants, including for group net metering, will be compensated and accounted for" and as we are entitled to do pursuant to RSA 362-A:9 II. RSA 362-A:9, II provides that "municipal or county aggregators under RSA 53-E may determine the terms, conditions, and prices under which they agree to provide generation supply to and credit, as an offset to supply, or purchase the generation output exported to the distribution grid from eligible customer-generators."

The Coalition was formed to support the creation of CPAs "as a competitive means for local governments to achieve their local policy goals and assume the responsibility of providing electricity service to their residents and businesses that do not choose an alternative supplier" and to "allow communities to promote renewable and distributed energy development, energy efficiency programs, price stability, access to innovative energy products, services, and rates, and local economic benefits through local control."[2] CPCNH wants to ensure equitable treatment of customers on competitive supply, CPA service, and utility default service, and help drive economic efficiency through open access to competitive markets and price signals that will help realize an affordable, equitable, and sustainable energy future.[3]

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[1] A complete list of our current members is attached as Attachment 3.

[2] Recitals, p.1 of the Joint Powers Agreement of the CPCNH, available under "Key Documents" at www.cpcnh.org.

[3] Paraphrased from "Regulatory and Policy Principles" p. 2 of the CPCNH Charter of the Regulatory & Legislative Affairs Committee.

Member municipalities “have substantial responsibilities and authority for land use planning, including adoption of master plans that may address transportation, utility and energy planning among other needs pursuant to NH RSA 674:2, zoning, development review, building and fire code administration, adoption of “stretch” codes pursuant to NH RSA 155-A:2, V, and creation of energy commissions pursuant to NH RSA 38-D for the study, planning, and utilization of energy resources and making recommendations on sustainable practices.”

Many CPCNH member municipalities have net metered electric accounts with renewable generation and own additional buildings and sites suitable for additional distributed generation (DG) and distributed energy storage (DS) facilities. Municipalities also have the authority to plan, construct, finance, own, operate, and sell power from distributed electric generation facilities pursuant to RSA 374-D, RSA 33-B and 53-E. Additionally, municipalities have the authority to finance with tax-exempt revenue bonds investments in new NEM projects as part of Commercial Property Assessed Clean Energy (CPACE) as part of multi-family and commercial energy efficiency and renewable energy upgrades pursuant to RSA 53-F. Many members have energy and climate action plans with aggressive renewable and clean energy goals, including goals to meet municipality energy needs with 100% renewable energy, with a focus on using as much local renewable energy as possible. Other municipalities are focused on ratepayer affordability with a goal to consistently ensure that CPCNH delivers the most competitive energy rates available.

Municipalities and their municipal aggregations (CPAs) are also uniquely situated to be “municipal hosts” (and their group members) which, pursuant to RSA 362-A:1-a, II-b “means a customer generator with a total peak generating capacity of greater than one megawatt and less than 5 megawatts used to offset the electricity requirements of a group . . .” As presently only municipal hosts can develop or sponsor NEM projects greater than 1 MW up to under 5 MW, CPCNH is particularly interested in the NEM 3.0 tariffs for greater than 1 MW.

As we represent both the customers we serve and the voters to whom we are accountable, our interest is acute in transitioning to a more market-based, competitive, and beneficial NEM 3.0 paradigm that will allow NH communities to accelerate the transition to a clean and sustainable energy future. Getting the price signals right in NEM 3.0 will result in the most cost-effective investments in the development and integration of distributed energy resources.[4] Better price signals will result in better investments.

Q. Are the goals of RSA 374-F relevant to CPCNH's proposal?

A. Yes. I think it will be helpful to consider some of goals and principles expressed in RSA 374-F, enacted into law over 27 years ago, to help inform the weight to be given to various rate design principles in evaluating proposed tariffs in this case (with emphasis added):

> **374-F:1 Purpose. –**
>
> I. The most compelling reason to restructure the New Hampshire electric utility industry is to **reduce costs for all consumers of electricity by harnessing the power of competitive markets**. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. **Increased customer choice and the <u>development of competitive markets for</u> wholesale and <u>retail electricity services</u> are key elements in a restructured industry** . . .
>
> II. A transition to competitive markets for electricity is consistent with the directives of part II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it." **Competitive markets should** provide electricity suppliers with incentives to operate efficiently and cleanly, **open markets for new and improved technologies**, **<u>provide electricity buyers and sellers with appropriate price signals</u>**, and improve public confidence in the electric utility industry."
>
> **374-F:3 Restructuring Policy Principles. – . . .**
>
> II. Customer Choice. . . . **Customers should be able to choose among options such as** . . . **real time pricing, and generation sources including interconnected self generation** . . . ."

While good rate and tariff design requires the balancing of a variety of principles and objectives, New Hampshire policy clearly gives considerable weight to customer choice, the development of competitive markets, including, of note, for **<u>retail</u>** electricity services, and the

[4] RSA 374-F:2, VII. "'Distributed energy resources' or "DER" means demand response, distributed generation, and distributed storage." "VI. "Demand response" means a reduction in the use of electricity by retail electricity energy customers in response to power grid needs, economic signals from their electricity supplier based on wholesale market prices, or time varying rates." VIII. "Distributed generation" or "DG" means a customer-generator as defined in RSA 362-A:1-a, II-b or a limited producer as defined in RSA 362-A:1-a, III, excluding qualifying storage systems and grid-interactive electric vehicles. IX. "Distributed storage" or "DS" means qualifying storage systems as defined in RSA 362-A:1-a, IX-a, grid-integrated electric vehicles when they are interconnected to a New Hampshire jurisdictional distribution grid behind a retail electric meter, or energy storage as defined in RSA 374-H:1, III, that are not participating in any wholesale energy markets administered by ISO New England as a registered asset or otherwise.

provision of "appropriate price signals." In this context, it seems apparent that "appropriate price signals" include those that achieve economic and operational efficiency and help achieve expressed public policy goals such as "maintaining safe and reliable electric service with minimum adverse impacts on the environment." New Hampshire statutory policy calls out specifically for customers to have the choice of real time pricing. Even as that concept and practice was still relatively new and limited to wholesale markets a quarter of a century ago, it was apparent to legislators that enabling retail load (customers) to respond to temporal price signals in supply markets is important to economic efficiency and productivity. While considerable effort has gone into developing wholesale supply markets in New England, we can do a better job connecting wholesale market price signals to retail consumption and supply markets and enabling small customers and customer-generators to have greater participation in retail electricity market choices.

Q. Are there other rate design principles that inform your testimony?

A. Yes, many of the principles first developed by James Bonbright and Alfred Kahn remain relevant today. Rates should yield the revenue required for regulated monopoly services in a stable and predictable manner. Rates should reflect cost causation, avoid undue discrimination, and fairly apportion costs among customer classes; and, I would argue increasingly, in this day and age, among individual customers. Furthermore, rates should promote economically efficient consumption and investment and promote innovation in supply and demand. Rates that are forward looking and reflect marginal costs, especially long-term marginal costs when long-term investments are involved, can efficiently harmonize utility and customer investments, choices, and benefits. Better translation of existing wholesale market prices signals for both generation services and transmission services to retail load and customer-generators are key in this regard.

Q. What statutory requirements need to be addressed in this proceeding?

A. The Commission summarized the issues presented in their 9/21/22 Order of Notice. They are based on the text in RSA 362-A:9, XVI(a) and XXIII. My testimony will address most, if not every issue referenced. Sandwiched in between those two paragraphs, giving a sense of when it was added to the statute, is RSA 362-A:9, XXI(a) which states:

> The commission shall consider the question of whether or not exports to the grid by customer-generators taking default service should be accounted for as reduction to what

> would otherwise be the wholesale load obligation of the load serving entity providing default service absent such exports to the grid. The commission shall use its best efforts to resolve such question through an order in an adjudicated proceeding, which may be DE 16-576, issued no later than *June 15, 2022* (e*mphasis added).*

No such resolution has occurred. Although not explicitly referenced in the order of notice, this matter is broadly within the scope of considering new net metering tariffs and other regulatory mechanisms. I did note this issue at the pre-hearing conference (Tr. at 26-27) and argue here that its resolution is intrinsic to others issues to be addressed and the implementation of any new alternative net metering tariffs. Responses from rate (price) signals such as exports to the grid in a net metering example need to be accounted for in the load settlement entity providing the rate signal. This is a critical component that will encourage rate innovation by entities other than the distribution utilities that are required to provide default service.

III. Summary of NEM 3.0 Proposal

Q. Could you summarize your NEM 3.0 tariff proposal?

A. Yes, in general, it is structured to enable movement to a transactive energy[5] rate structure for distributed energy resources. The proposal addresses customer-generators that have the necessary interval metering to support temporal price signals and customer-generators with monthly meter reads. Here is an outline of the basic elements:

- Continue existing grandfathering for NEM 1.0 and 2.0 customer-generators through 12/31/40. Target 9/1/24 as the start of NEM 3.0 for new projects and extend grandfathering for NEM 3.0 tariffs through at least 12/31/45. Those projects > 100 kW with approved interconnections before 9/1/24, even if not yet under construction, would be grandfathered into NEM 2.0 terms but have the option, along with NEM 1.0 customer-generators to transition to NEM 3.0. Any project up to 100 kW with a complete interconnection application pending as of the 9/1/24 effective date would also be grandfathered to NEM 2.0 unless opting for NEM 3.0.

[5] "Transactive Energy" or "TE" is defined at RSA 374-F:2, XII as "a system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter." This would involve enabling DERs to respond to temporal price signals related to balancing supply and demand within capacity constraints.

- Answer "yes" to the question of whether "exports to the grid by customer-generators taking default service should be accounted for as reduction to what would otherwise be the wholesale load obligation of the load serving entity providing default service, absent such exports to the grid." This is required in order for entities other than the distribution utilities to provide net metering services. This will help resolve several other important issues to be addressed including "maximizing net benefits while minimizing negative costs shifts" as called for by RSA 362-A:9, XVI(a).
- For greater than 1 MW customer-generators answer "yes" to the question in RSA 362-A:9, XXIII of whether monetary credit for exports to the grid "should include compensation for services and value not currently compensated including avoided transmission and capacity costs." This is required in order to align benefits to those that created it consistent with proper rate making principles outlined by Bonbright and Kahn. This also relates to maximizing net benefits and avoiding a substantial negative cost shift from other customers to customer-generators and avoids unjust and unreasonable cost shifting.
- Answer "yes" to the question in RSA 362-A:9, XXIII as to whether the cost of compliance with the electric Renewable Portfolio Standard (RPS), including prior period reconciliations, should be excluded from the monetary credit for exports to the grid. The RPS obligation compliance costs are associated with the use of electricity, not the generation of electricity making it appropriate to be excluded from the compensation from the export of electricity. This helps resolve several issues including minimizing negative cost shifts and avoiding unjust and unreasonable cost shifts as called for by RSA 362-A:9, XVI(a).
- Continue the basic structure of NEM 2.0 for projects up to 100 kW, except apply a different credit rate for the energy supply component of compensation for net exports to the grid. This has been applied in the New Hampshire Electric Cooperative's service territory with little impact to the adoption rate of net metered system development.
- Enable energy storage to be interconnected in NEM 3.0 as a part of all new and existing NEM customer-generators that convert to NEM 3.0. This pertains to maximizing net benefits from net metering.
- If necessary, stage implementation of new rate structures and business processes to ease any administrative burden on distribution utilities. As an example, limiting NEM 3.0 rate

changes to only projects > 1 MW, which are limited in number at present, may prove to be an efficient way for distribution utilities to develop the business processes needed to develop the necessary price signals

IV. Grandfathering

Q. Why should existing customer-generators or approved NEM interconnections be grandfathered into their existing tariffs?

A. RSA 362-A:9, XV requires NEM 1.0 customer-generators to be grandfathered by stating that:

> Standard tariffs that are available to eligible customer-generators under this section shall terminate on December 31, 2040 and such customer-generators shall transition to tariffs that are in effect at that time.

This was enacted in May 2016, 23½ years before the termination date. In DE 16-576 in Order No. 26,029 (6/23/17) for NEM 2.0 the Commission adopted a common feature of the two settlements[6] providing that:

> Customer-generators that receive a net metering capacity allocation while the new alternative net metering tariff is in effect to be "grandfathered" at the applicable net metering design and structure then in effect through December 31, 2040;

and further noted that:

> We clarify that any changes in underlying rates and rate designs would continue to apply to DG customers in the same manner as to all other customers in the same rate class, notwithstanding a customer-generator's grandfathered status.

This is good public policy and healthy for continued development and adoption of distributed energy resources as it provides predictability as to the terms and conditions of net metering going forward over a time period commensurate with the duration that the investment might be financed and relied upon.

In its 6/23/17 Order, the Commission also solicited comment on two previously unidentified issues related to grandfathering: 1) whether transferring ownership would affect grandfathering; and 2) "whether subsequent expansions of or modifications to DG systems would be entitled to net metering under the grandfathered tariff." In Order No. 26,047 (8/18/17) the Commission answered yes to both questions, as did most, if not all parties, and

[6] Order No. 26,029 at 23 and 51.

provided parameters as to what extent expansion was allowed within grandfathers. The Commission noted another new issue that was raised by Joint Commentators as to whether customers on original net metering (NEM 1.0) could migrate to the new tariff and solicited additional comment from parties. With no objection by any party and with support from Eversource in Order 26,055 (9/18/17), the Commission appropriately authorized customer-generators to migrate from NEM 1.0 to 2.0, but not back.

CPCNH is not aware of any reason why any of these grandfathering and expansion policies should not continue to apply, except that going forward CPCNH proposes that both NEM 1.0 and NEM 2.0 customer-generators have the option of migrating forward to NEM 3.0 tariffs, and that the grandfathering period for NEM 3.0 tariffs extend to at least December 31, 2045, or about 21½ years from when an order might be issued.

Also, the 2017 Order referred to grandfathering based on reservation of a NEM capacity allocation or reservation of a position in the interconnection queue by 9/1/17. CPCNH recommends that this be updated. At the time, there was a statutory limit to the amount of net energy metering allowed and in order to reserve a place within the interconnection queue, applications needed to have been completed with certain milestones to be met to maintain that position. In its June 23, 2017 Order, the Commission waived limits on the amount of capacity that could be net metered pursuant to RSA 362-A:9 I, as the law allows, so the NEM capacity allocation is no longer applicable. Instead, the Coalition proposes that new large customer-generators be grandfathered if they have an approved interconnection agreement in effect, even if not constructed or operational yet. For pending interconnections up to 100 kW, a complete and filed interconnection application should be sufficient to be grandfathered.

Finally, we recommend a target start date for NEM 3.0 tariffs of September 1, 2024, giving sufficient notice to potential DG customers, developers, and installers of any changes in NEM tariffs, assuming an Order approving any tariff changes by June. We also recommend the applying the proviso from the June 23, 2017 Order (at 56) to NEM3.0;

> If a utility is not capable of billing or crediting under the new net metering tariff as of the approved effective date, then DG projects will be billed and credited under the current standard net metering tariff rates until such time as the utility is capable of implementing the new net metering tariff provisions. Each utility should provide at least 30 days advance notice to its customers of the implementation date upon which billing and crediting under the new net metering tariff will commence.

V. Accounting for Exports to the Grid

Q. Why should "exports to the grid by customer-generators taking default service be accounted for as reduction to what would otherwise be the wholesale load obligation of the load serving entity providing default service absent such exports to the grid" as RSA 362-A:9, XXI(a) directed the PUC to use its best efforts to consider by June 15, 2022?

A. There are numerous reasons why this is essential, starting with the need for utilities to comply with Puc 2205.15 Net Metering by CPAs, that echoes the requirements of RSA 362-A:9, II:

> Puc 2205.15 Net Metering by CPAs.
>
> (a) CPAs shall determine the terms, conditions, and prices under which they agree to provide generation supply to and credit, as an offset to supply, or purchase the generation output exported to the distribution system from CPA customers with customer-sited distributed generation.
>
> (b) Pursuant to RSA 362-A:9, II, such generation output shall be accounted for as a reduction to the CPA customers' electricity supplier's wholesale load obligation for energy supply as an LSE, net of any applicable line loss adjustments, as approved by the commission.

In related discussions from technical sessions in DE 23-063, the Joint Utilities' Petition for Waiver of Certain Provisions of the Puc 2200 Rules, the parties have discussed what may be necessary to enable CPAs to serve net metering customers. Negative usage data is critical to the ability of CPAs, as well as CEPS, to serve most net metered customers as it provides the value on which to base credits or compensation for their exports to the grid. Appropriately it is essential to have that same amount of negative usage credited as a load reduction to the load asset being used by the CPA or CEPS offering the net metering service as the energy being credited by the net metering program is helping to reduce the wholesale load needs by the CPA or CEPS. Power exported to the distribution grid in New Hampshire by net metered customer-generators reduces a comparable amount of power that is supplied over the high voltage transmission grid from the ISO-NE market bulk generators. Furthermore, and in alignment with the laws of physics, because DG offsets load that is most proximate to it on the distribution grid (i.e., it travels the path of least resistance), it experiences less line and voltage transformation losses than power delivered over the high-voltage transmission grid over a long distance.

If the DG is not registered as a "Generator" participant in the federal ISO-NE wholesale market, then the power it exports to the distribution grid functions as a load reducer relative to load seen on the transmission grid. As such, it should be accounted for as reducing the load for charges for electric energy supply, generation capacity, transmission capacity and operation, and ancillary services. Consistent with rate making principles it makes sense that the supplier purchasing power from the net metering customer should see the benefit from that purchase through a reduction in load being purchased through the wholesale markets.

It has been the policy of the State of New Hampshire since the original enactment of net metering a quarter of century ago, that competitive suppliers should be able to set their own terms, conditions, and rates for net metered generation supplied to the grid. It is also statutory policy to enable and promote customer and community choice of energy suppliers, those who arrange to offset or supply your load, from both local and regional resources, and inclusive of the option of interconnected self-generation. This is expected to spur innovation and cost savings for NH ratepayers. It is clearly **not** the policy of this state, and indeed is inimical to our State Constitution, that net metered electric generation and the development and compensation of distributed energy resources should be a monopoly of the regulated utilities. Ensuring non-discriminatory open access to the electric system for wholesale and retail transactions is of paramount importance. CEPS and CPAs need to be able to receive their fair share of supply credit for their customer-generator's output in an accurate and timely manner. Currently, those exports to the grid are accounted for and reported as zero loads, not negative loads, in the load settlement process, creating a disconnect in the "but for" for causation principle.

However, before the distribution utilities can come into compliance with RSA 362-A:9, II and Puc 2205.15, the Commission first needs to approve any applicable line loss adjustments to factor into the net load reduction relative ISO-NE load obligation. CPCNH intends to soon file with other interested parties a petition requesting an adjudicated proceeding for such an approval and the tariff changes necessary to implement load settlement for suppliers that takes into account exports to grid by their customer generators.

Q. How does this relate to this docket?

A. The direct nexus with this docket arises from the fact that in our discussions with the Joint Utilities and other parties about the load settlement process and how it would need to change to allow CPAs to account for NEM exports to the grid, Eversource representatives indicated that changing this process would necessitate changing the load settlement process for all suppliers, including CEPS, and default service suppliers. We concur. This change would also result in more just and reasonable rates for default service customers because presently, the load reduction benefit of unaccounted for DG is socialized to all load in an obscure and non-transparent calculation where it is of limited benefit to customers. This reduction of this "residual" calculation to balance the difference between the wholesale meter reads (at the tie or substation interconnection between distribution and transmission) and retail meter reads for each hour of the year should be welcomed by all parties. Absent NEM DG, the difference between these two readings would be mainly attributable to line losses, on average perhaps, close to the published line loss rates. However, with all the unaccounted-for energy from NEM DG, the Joint Utilities concede that the apparent difference between these two could go negative at some hours of the day;[7] meaning that it may appear that it requires the purchase of less than 1 MW of ISO-NE power to supply more than 1 MW of retail load, when normally it might require 1.07 MW of ISO-NE power to supply 1 MW of retail load due to line losses.

Part of this distortion may arise from the lack of utility data on how net metered DG affects the load/production profile of customer-generators. Discovery has helped to point out that the distribution utilities do not have load profile research on net metered customers[8] except, perhaps, the hourly load data compiled for response to data requests. As a result, customers with monthly net exports to the grid contribute to a reduction of the load settlement profile of all suppliers with a scale down of all hours of load (24 hours / 7 days a week), by the class average load shape. This process ignores the fact that some hours for that customer actually have consumption (e.g. after dark for PV) and others have net exports. This process distorts the load profile of the utility default service provider from reality and compared with other suppliers who

[7] DR CPCNH 2-002 Attachment 5(a)-Eversource Data Response and 5(b) Liberty-DR
[8] DR OCA 2-014, Attachment 6(a)-Eversource, OCA 3-12 Attachment 6(b)-Liberty, Attachment 6(c)-Unitil

have few if any "0" monthly load NEM customers. The rate effects of this on all ratepayers is simply not clear.

Q. What additional benefits can come from this approach?

A. Treating exports to the grid by default service customer-generators as load reductions to the supplier's ISO-NE load obligation has an additional advantage because it enables a new approach to compensation for default service generation supply that can minimize negative cost shifts and maximize net benefits from NEM 3.0 as described below under VII.

In order to treat such exports to the grid as load reducers, generators that are selling the same power into the ISO-NE market should retire from that market first. This process is straight forward for Settlement Only Generators (SOG). Generators that wish to net meter and have capacity supply obligations to the region would need to first fulfill or unwind those obligations. This process is also straightforward as generators can participate in monthly or annual capacity reconciliation auctions or sell their obligation to parties that are able to fulfill it. Only a relatively few customer-generators are registered with ISO-NE as market participants. For Liberty, none of its 1,456 NEM customers are ISO-NE market participants. Only two are with Unitil, out of about 1,980 operating customer-generators. However, Eversource "holds 49 ISO-NE asset ID numbers for which the Company receives generation and capacity only payments" out of about 13,000 customer-generators. This seems to include most of the largest customer-generators, including about 10 hydroelectric facilities, that sold their output and capacity into the ISO-NE market as QFs before net metering as municipal group hosts These generators have assigned their revenue from energy and capacity payments to Eversource in return for the ability to net meter as a group host. Eversource has made clear that they do not require customer-generators to sell their power and capacity in the ISO-NE markets.[9]

CPCNH requested 2½ years of aggregated hourly export data for all 209 customer-generators that Eversource has interval data for in August 2023. Eversource was not able to meet the request but provided aggregated 2022 data for the seven customer-generators over 1 MW and a sample of 10 hydroelectric and 10 PV systems that are market participants. I matched that data up against the date and hour for each month that Regional Network Service (RNS) charges were incurred at ~$11.90/kW-mo, to estimate the amount of RNS charges for Eversource

[9] DR CPCNH 2-003, Attachment 7

customers that would have been avoided had they these customer-generators been retired fromthe ISO-NE markets and instead were treated as load reducers without accounting for line loss adjustments. Excerpts from that spreadsheet analysis, that included a total of 10 NEM production profiles, including all the summary data, is attached as Attachment 6. For the seven largest systems over 1 MW, the avoided RNS charges in 2022 would have totaled about $787,000 or the equivalent of about 1.67¢/kWh. There are another 42 systems not treated as load reducers that could realize this level of additional avoided cost value by retiring from the ISO-NE markets. There are a total of 10 PV systems, 1 gas (presumably, landfill methane), and 38 hydroelectric systems in this group. Adding the avoided Local Network Service (LNS) charges of about $1.63/kW-mo. would increase the avoided transmission costs from the seven largest systems to about $900,000. However, it should be noted that since Eversource's LNS revenue requirement is specific to its "local" transmission system in New Hampshire only, accounted for separately from their LNS in Massachusetts and Connecticut, most of any reduction in LNS charges would reappear as part of the true-up of the LNS revenue requirement. It should be noted that this load reduction would also free up peak capacity for more beneficial electrification load, such as from electric vehicles and heat pumps, likely increasing this avoided cost value.

In Unitil's and Liberty's case however, their LNS load is a relatively small share of the total LNS load, and most of any cost savings that may rebound in future increased rate will shift away from their system and customers. In Liberty's specific case, as with RNS, to out-of-state transmission customers (because National Grid is their LNS provider and most of the other transmission customer load is in Massachusetts and Rhode Island). Although all transmission customers pay the same RNS rate, LNS rates vary by provider. In late 2022, Liberty's LNS rate was about $3.00/kW-mo. adding about 25% in cost savings to the avoided RNS rates and this year is $3.58/kW-mo.

The NH Department of Energy commissioned Value of Distributed Energy Resources (VDER) Study (10/31/22) concluded that "[f]rom a utility system perspective, under current

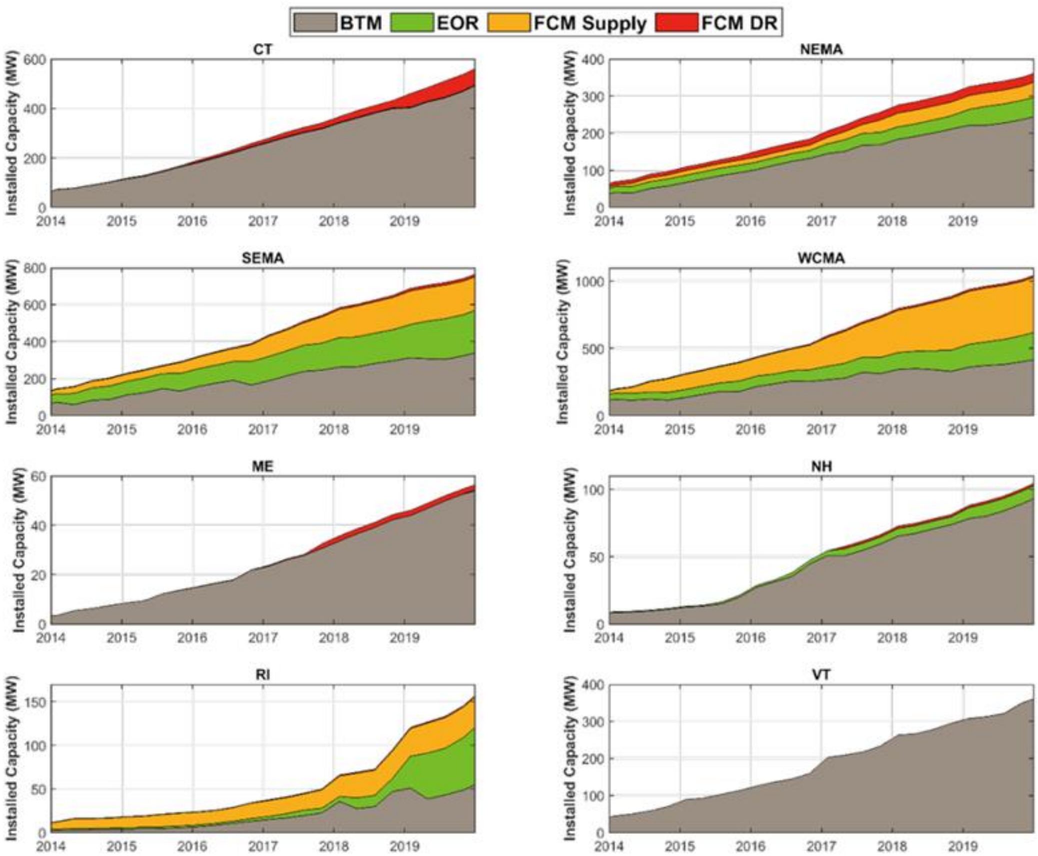
ISO-NE market rules, all systems provide greater value by passively reducing load than by participating as aggregated resources in the [ISO-NE] markets, …"[10]

Note the following graphic from ISO-NE's 2020 Behind-the-Meter (BTM) Solar Photovoltaic (PV) data documentation that shows the proportions of BTM PV capacity in-state that functions as a load reducer (gray shading) vs. market participant (green, gold and red wedges). (Also, note the scale is different for different states.) Vermont is the one state that has no or virtually no DG participating in ISO-NE markets because Vermont utilities, stakeholders and PUC determined back in 2009 that the greatest value was produced for Vermont ratepayers by treating all such resources as load reducers rather than selling their output and capacity through the ISO-NE markets. Vermont also asserted that such DG would also reduce RNS charges to Vermont, before ISO-NE and FERC amended the OATT to clarify that that is in fact the case.[11]

[10] "…with the single exception of micro hydro facilities. Micro hydro plants are able to consistently generate energy during the summer and winter peak reliability periods, thereby increasing their value in the [ISO-NE] capacity market New Hampshire Value of Distributed Energy Resources Final Report, p.59 (under "Key Findings"). Note, however, that if NEM 3.0 could provide credit for actual avoided capacity costs, along with actual avoided transmission costs, to micro-hydro (small systems that don't normally have interval metering), then micro-hydro could provide greater value as load reducers along with all other distributed generation and storage technologies than as ISO-NE federal wholesale market participants.

[11] Vermont Public Service Board, Docket No. 7533, Investigation Re: Establishment of a Standard Offer Program for Qualifying Sustainably Priced Energy Enterprise Development ("SPEED") Resources, Order Establishing a Standard-Offer Program For Qualifying Speed Resources,

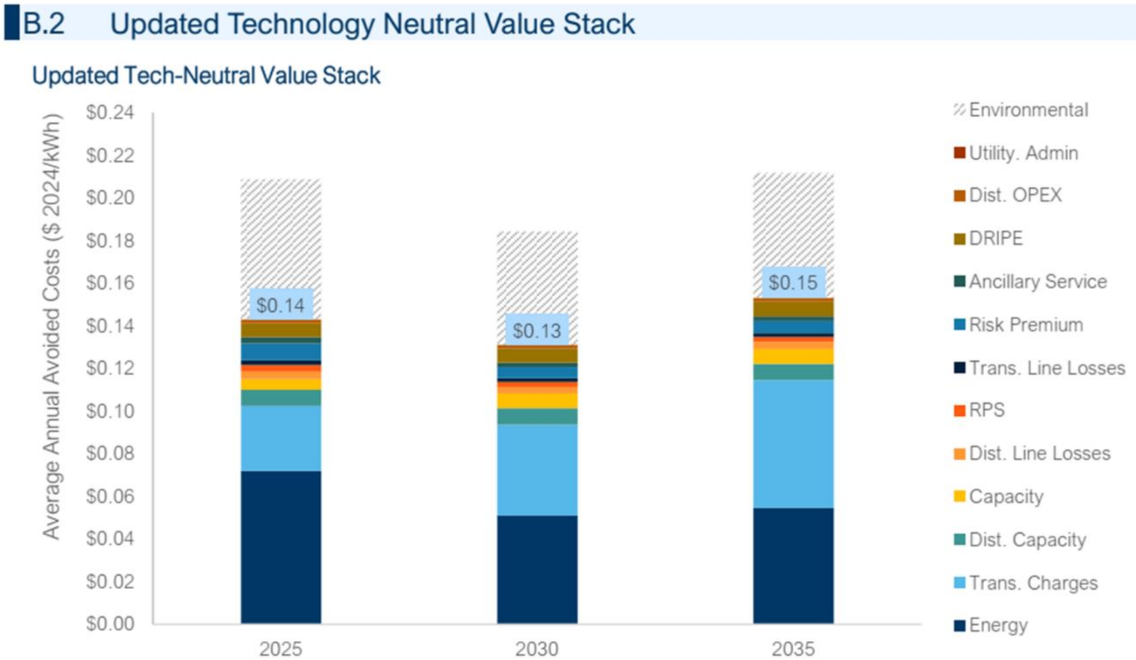
Note: Total capacity used in upscaling includes all categories except the FCM DR



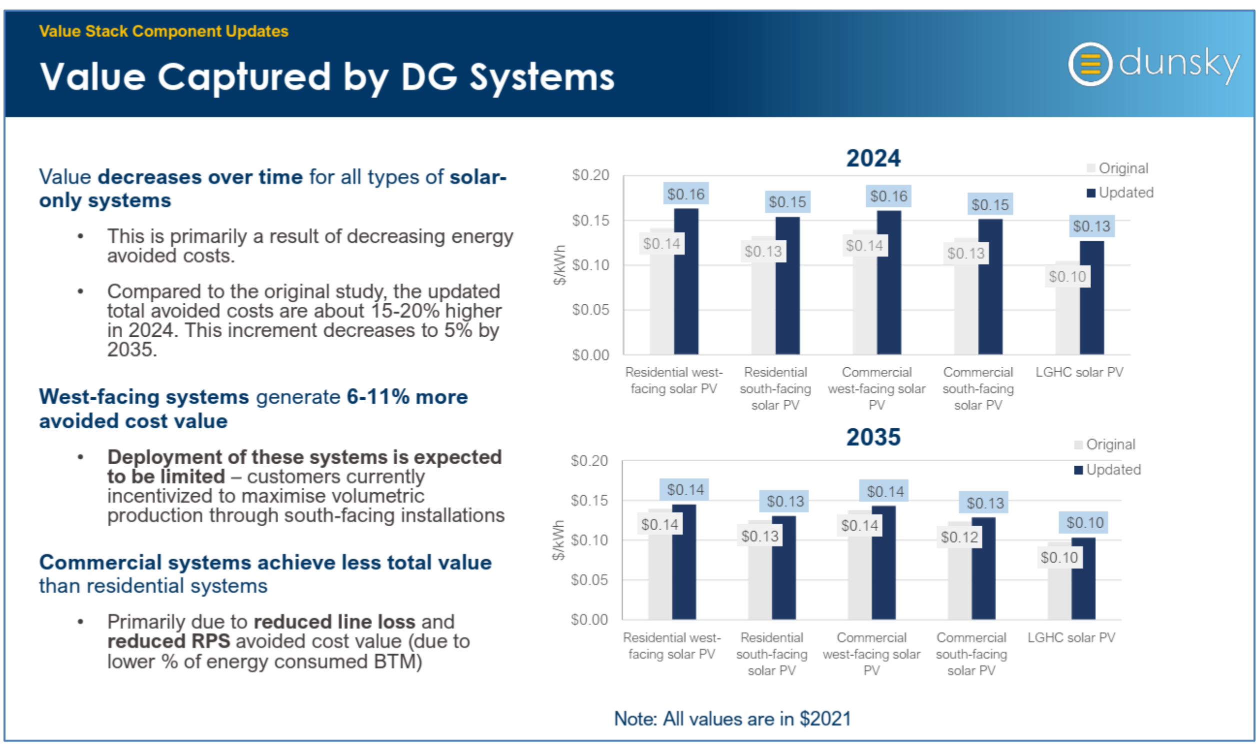
VI. Compensation for Avoided Transmission Costs

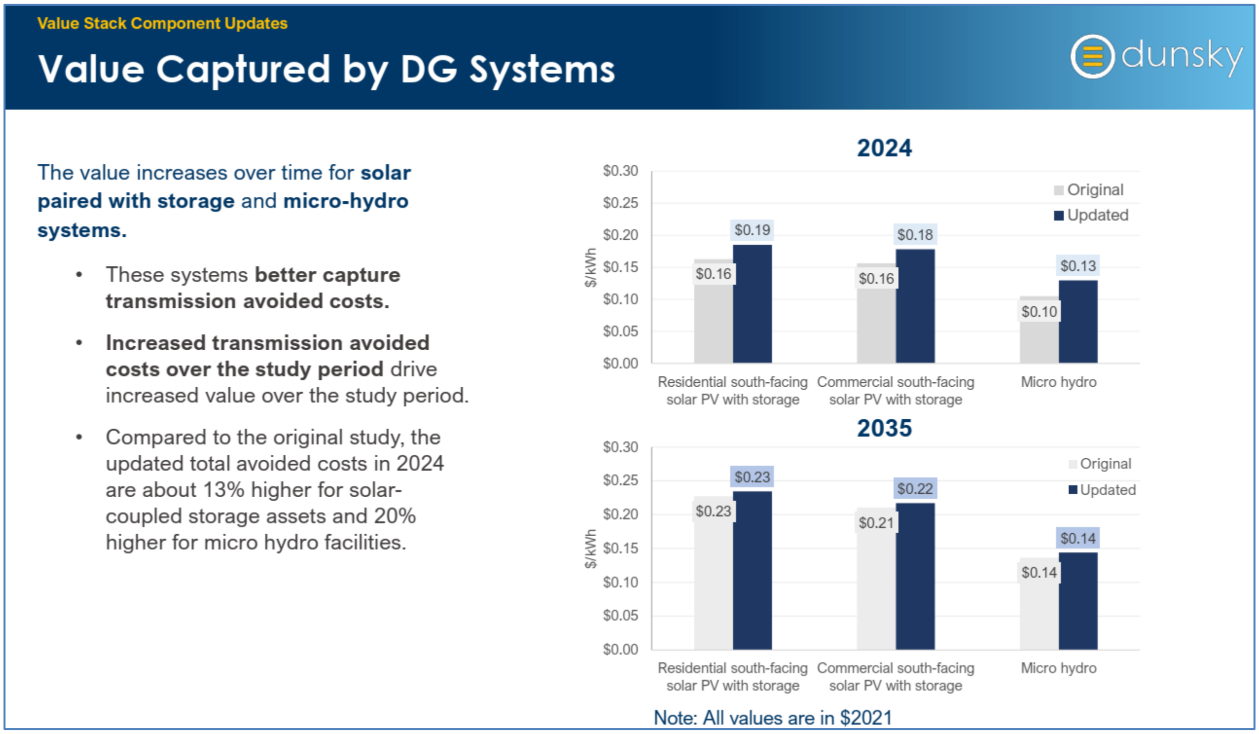
Q. For customer-generators greater than 1 MW, why should monetary credit for exports to the grid include compensation for services and value not currently compensated including avoided transmission" costs as RSA 362-A:9, XXIII directs the Commission to consider in this docket?

A. As the VDER study found, much of the value of DG (and distributed energy storage) functioning as a load reducer is realized by reducing transmission costs charged to NH ratepayers. For example, the VDER study update from this spring includes the following graphic labeled "B.2" that shows the value of reduced transmission charges for a technology-neutral generator, essentially a generator with uniform output 24/7, 365, like the #10 Landfill Gas generator hypothetical in my avoided Transmission Cost Rate Model:



The study also noted that certain DG, such as western-facing PV systems, or PV coupled with battery storage, can produce more value from avoided transmission (and capacity charges) than other systems, as illustrated in the following two slides from the Dunsky team's 4/20/23 NH VDER Stakeholder Presentation:





It is logical, and consistent with cost causation principles and the considerations in RSA 362-A:9, XVI(a) of: "balancing the interests of customer-generators with those of electric utility ratepayers by maximizing any net benefits while minimizing any negative cost shifts from customer-generators to other customers and from other customers to customer-generators" that those customer-generators that create quantifiable cost reductions be compensated for such reductions. Because periods of coincident peak can be correlated with high electricity prices in the day ahead and real time markets, due to the fact that the bid stack and clearing price for generation tends to get steeper with the dispatch of higher cost generation (i.e, the supply curve). If demand reduction occurs here, it tends to result in greater demand reduction-induced price effect (DRIPE) that benefits all ratepayers.

Q. What is your proposal for compensating customer-generators for avoided transmission costs that they cause?

A. For customer-generators with interval metering I propose they be compensated for actual avoided RNS charges and an appropriate portion of avoided LNS charges, calculated in a similar manner as Unitil proposed for their Kingston single-axis solar tracker project in DE 22-073, which was supported by the DOE, OCA, CENH, and approved by the PUC. The compensation to such customer-generators would be made in arrears after all relevant meter data and charges are known and would be charged to the Transmission Cost Adjustment Mechanism (TCAM) for recovery from all load charged for transmission. Because the sum of actual and avoided transmission charges would be approximately the same as actual transmission charges, absent ("but for") the exports to the grid at coincident system peaks by such customer-generators, other ratepayers would be neutral as to the overall rate impact, minimizing any cost shifting for transmission costs.

Q. Would you recommend any compensation for avoided transmission costs for customer-generators > 100 kW up to 1 MW that don't have interval metering?

A. Yes, those customer-generators should not be disadvantaged because the distribution utility has not provided them with interval metering. Using the best reasonably available data for estimating hourly production by such DG, an estimated average benefit from avoided transmission costs should be calculated annually and adjusted along with the annual adjustment of transmission charges. For the 10 different production profiles I analyzed, the value per kWh of avoided transmission costs all generally aligned in the range of 0.95¢/kWh to 1.75¢/kWh with many around 1.5 or 1.6¢/kWh, which is roughly one half of current transmission charges per kWh that range from 2.17¢ (Liberty G-2) and 2.28¢ (Liberty G-3) to 2.965¢ for Eversource Rate R, Standard Residential Service, and 3.09¢ for Unitil (all rate classes) and to 3.334¢ for Liberty Rate D.

VII. Compensation for Avoided Capacity Costs to LSEs from Customer-Generators.

Q. Why and how should customer generators be compensated for avoided capacity costs, particularly those over 1 MW in rated interconnection?

A. As with energy, ancillary services, and transmission cost allocation, ISO-NE tariffs and policies recognize DG and DS, if not participating in ISO-NE markets, as load reducers relative to capacity load obligations. To the extent that they export power to the distribution grid at the annual hour of coincident peak demand on which the next power year's capacity load obligations are allocated, they reduce the overall metering domains annual coincident peak demand.

When such a generator is on utility default service and is compensated for their exports to the grid based on the applicable default energy service rate, then that rate has embedded with it, credit for coincident peak demand and no further compensation is necessary. However, when such a customer-generator is on competitive or CPA energy service, their supplier can only afford to compensate them for such capacity load obligation reduction, if the supplier load asset has been reduced by the coincident peak load reduction.

Capacity load obligations are tracked by load asset, and since under our NEM 3.0 proposal, both positive and negative loads would be settled by load asset for all suppliers, allocation of the overall metering domain's coincident peak contribution to each load asset for its net load at the annual hour of coincident peak demand is appropriate. That net coincident peak contribution can then be allocated to each individual customer in proportion to their individual positive demand, based on either interval metered load or estimated load using class average load shape with those exporting to the grid at system peak still receiving zero capacity tags. For those customer-generators exporting to the grid without interval meters, their contribution to the reduction in load asset's net coincident peak contribution would be estimated using load/production profiles, based on the best readily available data, such as from customer-generators with interval meters or ISO-NE's reconstituted hourly production profile for BTM PV in New Hampshire.

This would also be more equitable for utility default service customers as they, as a group, would share in the credit for those utility default service customer-generators that contributed to the reduction in that load asset's net coincident peak contribution, since the compensation for such capacity reduction would come from default service customers as described in the next section.

VIII. Excluding RPS Compliance Costs from Utility Default Service Supply Credit

Q. Why should the RPS Compliance Costs, including for prior period reconciliations, be excluded from the utility default service supply credit for exports to the grid by customer-generators on utility default service?

A. RPS Compliance costs are based on the use of energy, not the production of energy. There is no basis for crediting production the benefit of RPS compliance costs as exports do not reduce the amount of energy use that RPS compliance costs are calculated from. Additionally, some net metered systems receive Renewable Energy Certificate (REC)s for their production, resulting in a duplicative benefit. This is also the primary step needed to adjust the utility default service supply credit down to a level where it more closely matches the value produced of NEM exports to grid as load reducers and so can be recovered from within default service rates as described below, eliminating the need for any cost shifting of the energy supply credit, which is the bulk of the compensation given to utility default service customer-generators for their exports to the grid.

Q. Can you illustrate the unreasonable cost shift and how this can result in duplicate compensation for NEM 2.0 customer-generators?

A. Yes, for instance, consider a hypothetical NEM 2.0 customer-generator that consumes 10,000 kWh per year and also has PV that produces the same amount of power but does so mostly in the half of the year with the longest days (summer) when they are a net exporter of 3,000 kWh and during the winter half of the year, they are a net consumer of 3,000 kWh. For illustrative purposes, say the default service rate is 10¢/kWh and the cost of RPS compliance embedded in that rate is 0.8¢/kWh, so over the course of the summer months they get $300 in bill credits and are charged $300 over the course of winter months. After the end of year, they have paid nothing for their energy supply but have created an RPS compliance obligation for the 3,000 kWh in electricity deliveries, which costs the utility $24 (3,000 kWh x $0.08) which they have to recover from other ratepayers. At the same time, the customer-generator can sell 10 RECs for their total production to the utility, say at $30/REC would be $300, so while benefiting from the existence of RPS, they pay nothing for their own RPS compliance costs, while shifting that cost to other ratepayers.

While in this example, the overall "missing money" problem for not contributing to RPS compliance is relatively small, it becomes more significant at scale. For example, Eversource indicated in discovery[12] that it compensated some 83,110,444 kWh in exports to the grid from NEM 2.0 customer-generators between 2018 and August 2023. The cost of RPS compliance shifted from those customer-generators to mostly other customers, assuming an RPS compliance cost of about $0.008/kWh, adds up about $665,000 over 6 years or roughly $100,000/yr For Unitil, between January 2020 through June 2023, NEM 2.0 customers exported some 52,243,426 kWh to grid. At $0.008/kWh, the cost of RPS compliance cost shift in that compensation would be about $418,000 or ~$120,000/yr. \

[12] DR Eversource Attachment CPCNH 1-003, Attachment 8

Q. What is your proposal for adjusting the default service energy supply rate so that it could be recovered from default service customers without increasing the rates they would otherwise pay without any change for default service, while reducing what they would otherwise pay in Stranded Cost Recovery Charges?

A. The bulk of the difference between the full default service rate and what the supplier is paid is mainly the cost of RPS compliance. There are a few other typically minor charges and credits that make up the difference, consisting of charges for the cost of administering default service, inclusion of working capital, plus prior period reconciliation of each of the elements in the default service rate for under and over collections. The two tables on the next page from Eversource's June 2023 default service filing illustrate this. The first is for the large customer group, where a rate that changes each month applies and is reasonably typical. The second is for the small customer group, which is unusual in that there is a very large prior period credit that reduces the customer rate below what the supplier is paid.

The yellow highlighted line # 4 is the Base Default Service Rate, which is the rate that must be charged to customers to cover the supplier's fixed price all-requirements price (all load that shows up). It is a bit larger than what is actually paid to the supplier to account for line losses between the retail meter and PTF boundary in the NH load zone where the supplier prices their supply offer. That amount and the assumed line losses are redacted and treated as competitively sensitive commercial information. Lines 7 and 8 are the estimated RPS compliance costs for the period ($0.00834/kWh) and the prior period reconciliation adjustment factor of a credit of $0.00607, which is unusually large, as is line 6. For the small customer group, there are two unusually large prior period over collection credits resulting in a retail default service rate that is lower than the Base Energy Service Rate.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE DBA EVERSOURCE ENERGY
ENERGY SERVICE RATE SETTING AUGUST 1, 2023 THROUGH JANUARY 31, 2024
LARGE CUSTOMERS (RATES LG AND GV)

Line	Large C&I (Rate LG & GV) Monthly Energy Service Rate Calculation	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24
1	Forecast Large C&I Wholesale Energy Service Load (MWhs)	20,932	16,455	15,983	16,920	20,492	21,321
2	Loss Factor	[redacted]					
3	Forecast Large C&I Retail Energy Service Load (MWhs)						
4	Wholesale Contract Price ($/MWh)	[redacted]					
5	Base Large C&I Energy Service Rate ($/kWh)	$ 0.09405	$ 0.07302	$ 0.07054	$ 0.11172	$ 0.20256	$ 0.26793
6	Energy Service Reconciliation Adjustment Factor ($/kWh)	$ 0.02099	$ 0.02099	$ 0.02099	$ 0.02099	$ 0.02099	$ 0.02099
7	Renewable Portfolio Standard Adjustment Factor ($/kWh)	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834
8	Renewable Portfolio Standard Reconciliation Adjustment Factor ($/kWh)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)
9	A&G Adjustment Factor ($/kWh)	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066
10	Large Customer Working Capital Adjustment Factor ($/kWh)	$ 0.00041	$ 0.00041	$ 0.00041	$ 0.00041	$ 0.00041	$ 0.00041
11	Total Large C&I Monthly Energy Service Rates ($/kWh)	$ 0.11837	$ 0.09734	$ 0.09486	$ 0.13604	$ 0.22688	$ 0.29225

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE DBA EVERSOURCE ENERGY
ENERGY SERVICE RATE SETTING AUGUST 1, 2023 THROUGH JANUARY 31, 2024
SMALL CUSTOMERS (RATES R, G AND OL)

Line	Small Customers (Rate R, G, & OL) Weighted Average Energy Service Rate Calculation	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	6 Month Total
1	Forecast Small Customer Wholesale Energy Service Load (MWhs)	331,769	260,801	253,323	268,179	324,789	337,928	1,776,789
2	Loss Factor	[redacted]						
3	Forecast Small Customer Retail Energy Service Load (MWhs)							
4	Wholesale Contract Price ($/MWh)	[redacted]						
5	Base Small Customer Energy Service Rate ($/kWh)	$ 0.09255	$ 0.07343	$ 0.06958	$ 0.10390	$ 0.18146	$ 0.23646	
6	Energy Service Reconciliation Adjustment Factor ($/kWh)	$ (0.00849)	$ (0.00849)	$ (0.00849)	$ (0.00849)	$ (0.00849)	$ (0.00849)	
7	Renewable Portfolio Standard Adjustment Factor ($/kWh)	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	
8	Renewable Portfolio Standard Reconciliation Adjustment Factor ($/kWh)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	
9	A&G Adjustment Factor ($/kWh)	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	
10	Small Customer Working Capital Adjustment Factor ($/kWh)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	
11	Total Small Customer Monthly Calculated Energy Service Rate ($/kWh)	$ 0.08657	$ 0.06745	$ 0.06360	$ 0.09792	$ 0.17548	$ 0.23048	
12	Forecast Small Customer Total Energy Service Cost, including Working Capital Requirement	[redacted]						$ 207,463,902
13	**Weighted Average Small Customer Energy Service Rate for the Period August 1, 2023 through January 31, 2024 ($/kWh)**							**$ 0.12582**

My proposal is that Default Energy Service Supply Rate for all NEM 3.0 customers would be based on the Base Energy Service Rate, discounted for the modest line losses that occur on the distribution grid between the point of export and the load it offsets (~2% to 3%). Under NEM 2.0, these exports are treated as zero load and do not reduce the amount of load the supplier must supply from the ISO-NE market. If these exports to grid are treated as reductions to the supplier's load obligation, then instead of paying the supplier for those kWh, the exporting customer-generators can be paid the same equivalent price (Base Energy Service Rate with an appropriate loss factor) as the supplier is paid, , eliminating the need to recover it through a stranded cost recovery charge.

To illustrate this scenario, consider that a group of default service customers consumes 1 million kWh in a given month and default service customer-generators export 100,000 kWh to grid during the same month. Currently, the default service supplier is paid for 1 million kWh at a given rate. Under this NEM 3.0 proposal, that supplier would only have to purchase 900,000 kWh and would be paid for that, while the remaining 100,000 kWh would come from customer-generators who would be paid an equivalent price (recognizing lower line losses for that supply), so that the consuming customers pay the same overall amount. This market-based rate eliminates the need to recover net metered exports through the stranded cost recovery charge and any cost shifting related to energy service supply credits.

IX. NEM 3.0 for up to 100 kW.

Q. Do you have a position on NEM 3.0 for systems up to 100 kW?

A. Yes, mainly that the basic structure of NEM 2.0 is continued, except that there would be a different credit rate for the energy supply component of compensation for net exports to the grid as described above. While I have not had to time to evaluate the distribution credit, my observation is that the VDER study found that there are some unrecognized avoided costs. Logically, there might be a greater credit for avoided distribution costs for NEM DG and DS under 100 kW than for larger systems, because they will offset load very nearby compared with most larger systems where the energy will typically travel further to offsets loads downstream and upstream, so it is possible that widespread smaller systems will free up more distribution capacity to support increased loads from beneficial electrification such as for electric vehicles and heat pumps. As Unitil pointed out in DE 22-073 "…each component of the utility distribution system contributes to electricity line losses and the amount of losses depends on the distance from the source to the load. Generally speaking, the longer the distance over which electricity is transmitted, the more electricity is lost."[13]

Where TOU rates are available, especially three-part TOU rates, CPCNH encourages the Commission to direct the utilities to enable export credit by TOU period and ensure that competitive suppliers and CPAs can also credit exports for energy service by TOU period as differential import and export rates.

X. Storage

Q. Why do you think the Commission can or should enable battery energy storage as part of NEM 3.0 tariffs?

A. First, the NH legislature enacted Chapter 243:8, NH Laws of 2023 (SB 166), effective 10/7/23, to amend RSA 374-H:2, I to read as follows, with new text in bold italics:

> I. The commission shall adopt rules ***or approve tariffs*** clarifying policy for the installation, interconnection, and use of energy storage systems by customers of utilities, and shall incorporate the following principles into the rules ***or approved tariffs***:

Thus, the Commission can enable energy storage systems through tariffs, such as a NEM 3.0 tariff, consistent with the cited principles. We propose that at this time, energy storage systems only be enabled in conjunction with DG as a part of NEM, and that stand-alone energy storage systems should be considered in a subsequent proceeding. The reason to do this is to improve the value proposition of NEM 3.0 in conjunction with the strong temporal price signal of being able to get credit for actual avoided costs at times of coincident peak demand, as well as potentially avoided generation capacity costs if served by a CPA or CEPS. This would help drive innovation and better solutions for steep ramp rates related to variable renewable energy resources. For example, fixed-orientation PV combined with storage could compete with single and dual axis PV tracker systems, with or without storage, for the investment that produces the most value for the least cost. Excess production around solar noon could be captured and stored for release later in the afternoon and evening to reduce peak demand,

[13] Testimony of Jacob S. Dusling for Unitil at 20.

creating more capacity for beneficial electrification without the need for costly new investments to serve growing peak demand. This will help maximize net benefits from net metering.

Q. What provisions should the Commission consider for interconnecting DS with DG in NEM tariffs (or rules eventually if desired)?

A. An important one would be from the Interstate Renewable Energy Council's (IREC) Model Interconnection Procedures, 2023 Edition, which allows the maximum export to be constrained to an agreed upon interconnection limit that is less than the sum of the potential export of each system if operated separately. The IREC model interconnection procedures were developed this way with the intention that storage could be added to existing NEM systems without increasing the interconnection rating as the battery would only discharge when DG is operating at less than full capacity or not at all. Below are those model procedures that the Commission could direct the utilities to adapt and incorporate into the interconnection standards by reference through their tariffs:

> **B. Limited-Export and Non-Exporting DERs**
>
> 1. If a DER uses any configuration or operating mode in Section IV.B.3 to limit the export of electrical power across the Point of Common Coupling, then the Export Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a DER must comply with the limits identified in this Section. The Export Capacity specified by the Interconnection Customer in the Application will subsequently be included as a limitation in the Interconnection Agreement.
>
> 2. An Application proposing to use a configuration or operating mode to limit the export of electrical power across the Point of Common Coupling shall include proposed control and/or protection settings.
>
> 3. Acceptable methods of export limitation include:
>
> a. ***Export Limitation Methods for Non-Exporting DERs***: . . .
>
> b**. *Export Limitation Methods for Limited-Export DERs:***
>
> i. <u>Directional Power Protection (Device 32)</u>: To limit export of power across the Point of Common Coupling, a directional power Protective Function is implemented using a utility-grade protective relay. The default setting for this Protective Function shall be the Export Capacity value, with a maximum 2.0 second time delay to limit Inadvertent Export.
>
> ii. <u>Configured Power Rating:</u> A reduced output rating utilizing the Power Rating Configuration Setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating. The configuration setting corresponds to the active or apparent power ratings in

Table 28 of IEEE Std 1547-2018, as described in subclause 10.4. A local DER communication interface is not required to utilize the configuration setting as long as it can beset by other Certified means. The reduced power rating may be indicated by means of a Nameplate Rating replacement, or a supplemental adhesive derating tag to indicate the reduced power rating. This method must be Certified to IEEE Std 1547.1-2020. Use of a configured power rating not applied to individual generator(s) shall require evaluation under mutually agreed upon means.

c. Export Limitation Methods for Non-Exporting DERs or Limited-Export DERs:

i. Certified Power Control Systems: A DER may use Certified Power Control Systems to limit export. A DER utilizing this option must use a Power Control System and an inverter Certified per UL 1741 by a Nationally Recognized Testing Laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit Inadvertent Export.28 This option is not available for interconnections to Area Networks or Spot Networks.

ii. Agreed-Upon Means: A DER may be designed with other control systems and/or Protective Functions to limit export and Inadvertent Export if mutual agreement is reached with the Utility. The limits may be based on technical limitations of the Interconnection Customer's equipment or the Electric Delivery System equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the Interconnection Customer may use an uncertified Power Control System, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the Utility.

XI. Implementation Issues & Schedule

Q. What are the implications for utilities' administrative processes required to implement this NEM 3.0 proposal and related regulatory mechanisms?

A. The implications for these processes appear to be manageable, though it has been suggested by the distribution utilities that it would require time to implement allocation of load settlement and coincident peak contribution. In the last proceeding, the utilities proposed to implement a differential credit rate for the distribution rate component. In effect, this would result in a similar application for energy service and transmission for customer-generators over 100 kW. The fixed rate could be adjusted annually as part of the annual TCAM filing. The individual calculation for actual avoided transmission credit for large customer-generators is simple enough and could initially be done manually, if necessary and perhaps only quarterly or annually until automated, because the universe of customer-generators that this would apply to is not large,[14] even if interval-metered customer-generators on NEM 2.0 migrated to NEM 3.0. For automation, it would involve looking up a specific meter read for the monthly hour of coincident peak demand in a meter database and applying a uniform rate to any exported meter read for that hour. This would involve modifications to the billing system to fully automate, but not unlike what was done for the distribution rate credit.

To the extent some of these changes may take some time to fully implement, they could be phased in after the NEM 3.0 adoption date with new customer-generators served by NEM 2.0 terms until the new features are ready for use or initially limited to large projects, such as those over 1 MW in rated capacity.

Considering the large and growing number of NEM interconnection requests, such an approach could deliver significant net value by providing better price signals to incentivize DG and DS that target output at coincident peak demands helping leverage private investment to reduce impacts on the distributions system.

XII. Other Issues

Q. What other issues does the Commission need to consider in this docket that you want to address?

A. Time-based rates, as referenced in RSA 362-A:9, XVI(a) for consideration by the Commission, would be implemented to a very significant extent by the temporal price signal on actual avoided transmission costs available to customer-generators with interval metering, as well as through access to TOU rates for smaller systems referenced under IX above. Enabling CPAs to serve NEM customer-generators by receiving credit for their exports to the grid in load settlement and in reducing coincident peak contributions for capacity supply obligations would enable CPAs and CEPS to couple strong marginal price signals on generation and transmission costs with dynamic energy pricing options based on day-ahead the real-time prices and could unlock market-based innovation.

[14] In Eversource's territory, there are only about 209 such customers and in Liberty's territory, there are only 52 such customers.

Maximizing net benefits in the manner described in this NEM 3.0 proposal, would obviate any need to limit "the amount of generating capacity eligible for such tariffs" or impose a limit on "the size of facilities eligible to receive net metering tariffs."

XIII. Conclusion

Q. Does that conclude your testimony?

A. Yes, it does. Thank for your attention and interest.