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

Rebuttal Testimony of Clifton C. Below

January 30, 2024

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Attachments

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. Did you file direct testimony in this proceeding on behalf of the Coalition?

A. Yes, on December 6, 2023.

Q. And what is the purpose of this rebuttal testimony?

A. The purpose is to rebut and reply to certain positions and recommendations made in direct testimony by or on behalf of the NH Department of Energy (DOE), the Office of Consumer Advocate (OCA), and Clean Energy New Hampshire (CENH).

II. NH Department of Energy Testimony

Q. Where does the Coalition take exception to the testimony of DOE?

A. There are two main issues to which we take exception. First, DOE recommends that "the current alternative net metering compensation rate continue for all DG systems less than 5 MW"[1] and supports that recommendation with the assertion that "these rates avoid any unjust and unreasonable cost-shifting currently."[2] And second, DOE proposes "that the renewable energy portfolio costs and prior period reconciliation be included"[3] in the default service rate credit for

[1] Direct Testimony of Elizabeth R. Nixon, Mark P. Toscano, Deandra M. Perruccio, 12/6/23, p. 22, lines 5-6.
[2] *Id* at Bates p. 16, line 5.
[3] *Id* at 22, lines 11-12.

net metered (NM) customer-generators on utility default service. On other matters CPCNH is in general agreement with DOE, including their recommendation to move customer-generators onto appropriate TOU rates as available, though that may provoke challenges for Eversource since they do not currently have a metering solution to enable such. We recommend that the Commission and Eversource explore the solution that Liberty has implemented at an apparently reasonable cost, to use existing cellular data services to collect interval meter data, in conjunction with an existing Itron meter data management system, to offer TOU rates. Further, the Commission may want to consider, within a NEM 3.0 construct, that movement of NM generators to cost causation-based TOU rates (when available) be an option, if not a requirement, with both consumption and exports charged or credited based on TOU rate components.

Q. Focusing on the exceptions, why does the Coalition disagree with DOE on simply continuing the existing NEM 2.0 construct?

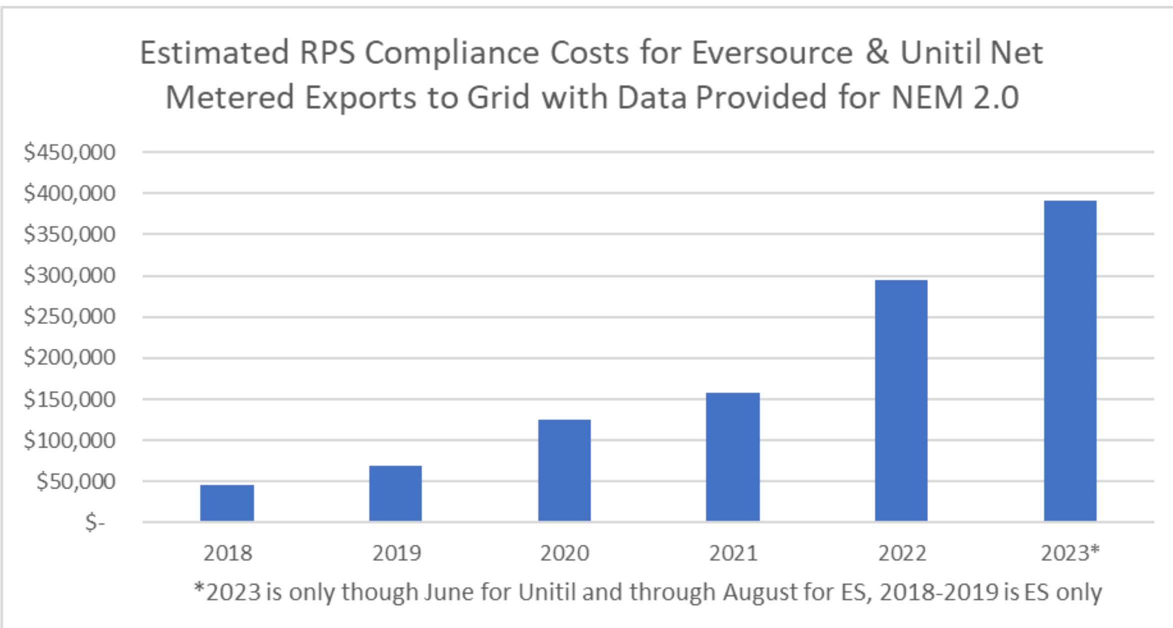
A. As discussed at some length in my direct testimony, there is a substantial cost shift of transmission costs onto NM customer-generators > 100 kW by not recognizing the value that they produce by reducing transmission charges to New Hampshire (unless they are also ISO-NE market participants which do not produce such value). It simply does not make any policy sense to have a sharp cliff, such that a 100 kW customer-generator earns 100% transmission rate credit for exported power, while a 101 kW customer-generator receives no such credit. The Coalition's proposal to give credit for actual avoided transmission costs where interval metering is available will help to maximize the net benefits of net metering by helping to suppress coincident peak demand, freeing up capacity on the grid for beneficial electrification and/or helping avoid expensive new capacity upgrades while also resulting in Demand Reduction Induced Price Effect (DRIPE) that benefits all customers. The Coalition also finds merit in the CENH argument that some degree of distribution credit should be given to generation >100 kW and recommends that that proposal be considered.

Q. What is the problem with including credit for RPS compliance costs and prior period reconciliation in the export credit rate?

A. As detailed in my direct testimony, when a customer-generator exports power to the grid, they do avoid the need to purchase that same power from the ISO-NE market (as well as capacity on the annual hour of system peak), including marginal line losses up to the bulk generators delivering power over the transmission grid. However, those exports to the grid do not avoid any RPS compliance costs when that power is consumed by load, resulting in a cost shift primarily to ratepayers who are not participating in net metering. At the same time, those who participate in NM pay virtually nothing for their own RPS compliance costs, effectively double-dipping from net metering if the earn revenue from the sale of RECs as well, which on the face of it, is simply unjust from a cost causation perspective.

In my direct testimony, I provided an example of an individual customer and the resulting impact, which in terms of absolute dollars looks small, but this issue needs to be considered at scale and over the life of any ‘grandfathering’ arrangements. As an example, assume a large hydroelectric customer-generator that exports 7 million kWh/year as a municipal host, nominally to “offset” the load of a group of government accounts. That exported production will generate 7,000 Renewable Energy Credits, worth, perhaps, $30 each or ~$140,000 in revenue. With an assumed RPS compliance cost of $0.008/kWh when that same power is delivered to consuming customers, those 7 million delivered kWh will generate a compliance obligation of $56,000. However, since the credit rate equals the consumption rate for default service there is no revenue from the resale of that 7 million kWh to cover the RPS compliance cost of those 7 million kWh and all but a small fraction of that cost is shifted to customers not participating in NM, such as through the SCRC, as they neither benefit from the sale of the RECs, nor the avoidance of RPS compliance obligation.

While this has been a fairly minor cost shift to date, so perhaps "reasonable" in the overall scheme, the total involved here is increasing and likely to continue to increase with a potential doubling of participation in coming years as well as likely increasing RPS compliance costs as the region rachets up the compliance obligation as well as the demand for RECs. To illustrate this point, I have compiled the export data provided to us in response to CPCNH 1-001, attached hereto and assumed an RPS compliance obligation of $0.008/kWh delivered/consumed:



Of note is the capacity of proposed net metered projects in the interconnection pipeline. For example, as of June 2023, Eversource had about 8,541 NEM 2.0 customer-generators, only 112 of which were > 100kW to 1 MW, and only 4 of which were > 1 MW. As of September 30, 2023, Eversource had 3,069 NM applications pending in 0-100 kW size, 49 >100kW to 1 MW, and 62 projects in the > 1 MW size.[4] While not all of these projects may ultimately go on-line, it is an indication of the potential rapid growth of NM generation exported to the grid. This could result in quite a large pipeline of cost shifting for RPS compliance over the term of any grandfathering without any justification for avoided costs. Now is the time to correct this unjust cost shifting going forward.

III. Office of the Consumer Advocate Testimony

Q. Where does the Coalition take exception to the testimony on behalf of the OCA?

A. First, we disagree with the recommendation that the "Commission should keep the NEM 2.0 compensation mechanism in place for the next two to three years."[5] However, we agree with the recommendation "that the Commission begin to consider changes to NEM that are more sustainable for the long term"[6] and believe that CPCNH has made material recommendations in our direct testimony that will move NEM 3.0 in that direction and see no reason to wait to consider such changes, except to allow necessary time to fully implement such changes.

Second, we disagree with the recommendation that the "Commission should require the joint utilities, by December 1, 2025, to submit an analysis of whether and how to modify NEM 2.0."[7] This recommendation seems to presume that net metering is a monopoly function of the Joint Utilities and we should look to them for recommendations on how that monopoly might be continued (or not, in compliance with NH policy and law[8]) and make changes when the order of

[4] From Eversource Response to CPCNH 1-001 and 1-002, attached hereto.
[5] Direct Testimony of Tim Woolf and Eric Borden On Behalf of The Office of the Consumer Advocate, 12/6/23, p.37, lines 6-7
[6] *Id* at 31, line 12-13.
[7] *Id* at 38, lines 3-5.
[8] Since 1996 NH law has called for all customers to have a choice of generation suppliers, which necessarily includes those that net meter. From its origin in 1998, NH's net metering law has called for competitive electricity

notice in this docket invited just such an analysis and yet the Joint Utilities indicated their satisfaction with the status quo. It would be appropriate for the Commission to require the Joint Utilities to make data for such an analysis more readily available, which should include starting to deploy interval metering for new net metered customer-generators as soon as possible to help provide such data, since the value of distributed generation (DG), and particularly storage, is highly time dependent. We do agree however that net metering compensation mechanisms should be periodically reviewed and should be based on avoided costs and value realized. In my testimony, I made a number of recommendations to recommend such a transition to interval metering for net metering customers sooner than later. We also agree that we should be focused on optimizing investment and operation of net metering to the benefit of the overall grid and the policy objectives of the state and local communities.

Q. What is your view on the OCA's ideas for converting to a long-term fixed compensation rate for NM exports to the grid?

A. We disagree with the OCA's recommendation that the proposed fixed "compensation rate after 2025 should be 'grandfathered' with respect to future solar compensation changes for a

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suppliers to be able to determine the terms, conditions, and compensation to be paid to their customer-generators. When it was brought to the attention of the legislature in 2020 that the utilities were not crediting net metered exports to the grid against the supplier's load, they amended RSA 362-A:9, II to include this provision regarding how to account for such exports: 'Such output shall be accounted for as a reduction to the customer-generators' electricity applicable line loss adjustments, as approved by the commission." The bill that created net metering in 1998, amended the purpose statement of RSA 362-A: 1 to add that the goals of the chapter, now including net metering***, "should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3."*** The NH Supreme Court has further grounded this policy in our state constitution when it noted that ***"…[L]egislative grants of authority to the PUC should be interpreted in a manner consistent with the State's constitutional directive favoring free enterprise. Limitations on the right of the people to "free and fair competition"... must be construed narrowly, with all doubts resolved against the establishment or perpetuation of monopolies. RSA 374:26 thus should not be interpreted as creating monopolies capable of outliving their usefulness."***
Appeal of PSNH, 141 N.H. 13, 19 (1996) (emphasis added) (internal citation omitted).

period of thirty years, the expected lifetime of solar DG."[9] There is no apparent policy basis for this, and the OCA's own analysis indicates the payback period for NM investments is on the order of half of that time. Thirty years is also likely longer than the typical financing period for such initial investments. More importantly, it is contrary to the goal of optimizing NM investment and value to the grid. Increasingly, it is becoming apparent that integrating storage (and demand response, such as when EVs charge) with DG is a necessary path to optimizing the investment and operational value of DG. That means that dynamic price signals, such as when coincident peak demands occur, will grow in importance over time and should be reflected in NM compensation schemes going forward, so that compensation can remain aligned with cost causation and avoided costs. The DOE recommendation to integrate TOU rates into NM is one way to achieve this and would be a great improvement over fixing a per kWh rate, which values all kWh the same, as NEM 2.0 does. As CENH points out in their direct testimony, and with regard to the Unitil proposed investment in a large single-axis tracker PV array,[10] careful attention to the temporal dimension of avoided costs results in a more optimal investment that can produce more value to the grid. We need to make these temporal price signals available to NM customer-generators going forward so we see more optimal investments.

IV. Clean Energy New Hampshire Testimony

Q. What exceptions do you make to the CENH testimony?

A. We have no exception to the testimony of Mr. Thomas Beach and have only two substantive disagreements with the direct testimony of Mr. David Littell. The first is with regard to the recommendation that NEM 2.0 compensation for systems up to 100 kW be continued as is,

[9] *Id* at 38, lines 3-5.
[10] *See* DE 22-073.

with the exception of an increase in the distribution credit to 50% of volumetric charges. The increase in the distribution credit seems reasonably justified; however for the reasons stated above and in our direct testimony, we do not believe it is just and reasonable to continue crediting back RPS compliance costs (as well as prior period reconciliations, and administrative costs, including working capital, of administering default service) incurred by the utilities as part of export compensation, because these are not costs that are avoided by customer-generators, resulting in undue cost shifting.

The other exception is to CENH's recommendation for a fixed volumetric credit for transmission costs for exports by NM customer-generators in the > 100 kW to 1 MW range. We have two issues with that recommendation. First, it only seems to extend up to 1 MW. As noted in the Unitil single axis tracker proposal, there are many opportunities for DG projects in the 1 to 5 MW range, and a large part of the value proposition is the "load reducer" value, including avoided transmission costs. Additionally, if a blanket fixed credit is given, then there is no real price signal to optimize for production that will actually reduce those coincident peaks, nor create an incentive to pair battery storage with these projects. Providing the right market signals will help make capital investment in distribution and transmission to be more efficient in the future, reducing costs for all ratepayers. An easterly-facing array might receive the same credit as a south or western facing array or even a tracking array, though each may perform quite differently. As most, if not all systems in the > 100 kW are amenable to interval metering, better investment decisions and more optimal value will result if larger customer-generators receive credit for actual avoided costs. This is why CPCNH has proposed that starting with > 1 MW systems, transmission credit be based on actual avoided transmission charges, and be applicable to smaller systems > 100 kW as interval metering and utility billing systems can be modified to support such.

Q. Do you have any other concerns with this proposal to provide a transmission rate credit for larger systems?

A. Yes, another serious problem is that some number of customer-generators who might qualify for such a credit do not actually function as "load reducers" relative to transmission (as well as capacity and energy) because they are simultaneously selling their energy (and capacity, in many, if not all cases) into the ISO New England interstate wholesale market. We agree with CENH and the Dunsky report that greater value for DG (and storage) can be realized by treating them as "load reducers" than as ISO-NE wholesale market participants. In discovery, Eversource identified 49 customer-generators[11] that sell their power into the federal (ISO-NE) wholesale market and Unitil identified two.[12] While the output onto the distribution grid from these 49 generators nominally offsets load on distribution grid, that load is actually "reconstituted" or added back into apparent load at the boundary of transmission and distribution for allocating all ISO-NE costs.

Furthermore, such dual participation in state jurisdictional net metering while also selling the power into the ISO-NE market should never have been allowed in the first place. Evidently, it is a construct that Eversource started doing without any explicit advance PUC approval. Since the original enactment of net metering in 1998, NH law (RSA 362-A:1-a, II-b) has required that net metered customer-generators be "located behind a retail meter" meaning behind a state-

[11] Eversource Response to DR CPCNH 2-003 found on Bates pp. 69-70 of Attachments to CPCNH Direct Testimony.

[12] Unitil Response to DR CPCNH 1-003(d) (attached).

jurisdictional meter. Under the Federal Power Act (FPA), states have exclusive jurisdiction over retail sales of electricity (along with within-state wholesale sales, such as under net metering), while FERC has exclusive jurisdiction over sales at wholesale in interstate commerce. Most of the 51 NH NM customer-generators participating in the federal markets are hydroelectric facilities that presumably were selling as QFs into the ISO-NE market before signing up for net metering. At that point, their meters were interstate wholesale meters under FERC jurisdiction meeting certain telemetry requirements, including interval reporting, as required by ISO-NE. While it is conceivable that the utilities have added a second parallel retail meter that they read separately from the wholesale meter, it seems doubtful. It is not really possible for a meter to be both a retail meter (state jurisdictional) and a wholesale meter (for interstate wholesale sales under federal jurisdiction). This can be observed by asking a simple question. If the meter is a retail meter, then the state, through the PUC, DOE or otherwise, would have the authority to specify the capability of the meter and could order that the existing interval meter be replaced with a meter that is only read monthly. While there might not be a good policy reason to do this, the question is whether it is within the state's jurisdiction to do so. Likely FERC would pre-empt such a state requirement and if so pre-empted, then it is not truly a retail meter.

Furthermore, for those customer-generators > 1 MW participating in the ISO-NE market, the definition of "Municipal Host" enacted in 2021 requires that their generating capacity be "used to offset the electricity requirements of a group consisting exclusively of one or more customers who are political subdivisions". However, if that power is being sold into the ISO-NE market, then FERC approved tariffs and ISO-NE operating procedures prohibit that same generation from being used to offset electricity requirements on the distribution grid, making the definition a legal fiction and requiring NH suppliers to purchase the entire load of such customers from ISO-NE without any offset.

Finally, I will note that the Commission has a responsibility to approve only those tariffs and terms and conditions for net metering that are consistent with both state and federal law. A net metering regulation that allows for compensation to generators participating in FERC jurisdictional markets in excess of FERC approved market rates may be impermissible and pre-empted by federal law. In 2016, the US Supreme Court in Hughes v. Talen[13] unanimously upheld FERC and lower Court decisions striking down a Maryland regulatory scheme that compensated a generator selling energy and capacity into the interstate PJM market in excess of the revenues received from that FERC jurisdictional market. The FPA grants FERC exclusive jurisdiction over rates paid for electricity and generation capacity sold in interstate wholesale markets. In organized markets like ISO-NE and PJM, FERC has determined that those rates are the market rates.

The Maryland state program was struck down because it "disregarded an interstate wholesale rate required by FERC" by requiring utility compensation over and above what the generator was receiving in the PJM market. This case is directly analogous to what is happening currently with the ~51 net metered generators who are paid the full default service rate, which is greater than the value of energy and capacity from selling that same power into the ISO-NE market at FERC approved rates.

Likewise, on 9/29/19, FERC granted a petition for a declaratory order[14] finding that NH SB 365 (Chapter 379 NH Laws of 2018) was pre-empted by federal law and invalid as a result

[13]Hughes v. Talen Energy Mktg., LLC, 578 U.S. __ (2016) https://supreme.justia.com/cases/federal/us/578/14-614/
[14] FERC Docket No. EL19-10-000, https://www.ferc.gov/sites/default/files/2020-05/E-22.pdf

because it mandated that NH utilities purchase the generation of certain biomass generators at a rate equal to 80% of the utility default service rate rather than at the ISO-NE market rates. FERC found that: "SB 365 requires utilities to offer to purchase the net output of eligible biomass and waste facilities at a state-established rate. As explained below, this requirement establishes a rate for wholesale sales of electric energy in interstate commerce, which intrudes on the Commission's [FERC's] exclusive jurisdiction over wholesale sales of electric energy in interstate commerce. We therefore conclude that the rate established by SB 365 is preempted by the FPA."

Thus, we recommend that the PUC prohibit net metered generators from also selling their power and capacity into the ISO-NE market by refraining from registering as generators with ISO-NE or retire after fulfilling or discharging any capacity supply obligations in order to continue participating in net metering. Alternatively, the Commission could simply prohibit any compensation for transmission costs to such generators and require an annual calculation as to how much avoided transmission costs that NH has foregone as a result of such continued participation in both markets which would be deducted from their energy compensation. Administratively and from a litigation risk mitigation perspective, full abstinence from such dual participation would be best.

In my direct testimony, I noted that this issue might be resolved through legislation. The second part of HB 1600 as introduced would have done so, but at the public hearing on the bill on January 29, 2024, the prime sponsor indicated that he would offer an amendment to strike that part of the bill since this issue was pending before the Commission. Others, including CPCNH, also indicated that this issue was before the Commission and might best be resolved in this docket, as it does go the question of how to maximize benefits of net metering while minimizing negative cost shifting. If the Commission would like to hear from other parties on this, a separate legal briefing and/or oral argument could be scheduled. Pursuant to RSA 363:18, the Commission also has the authority to confer with FERC on this matter.

V. Conclusion

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.