STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Electric Distribution Utilities

DOCKET NO. DE 22-060

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

SETTLING PARTIES REPLY BRIEF

Public Service Company of New Hampshire d/b/a Eversource Energy; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty; Unitil Energy Systems, Inc. (together the "Electric Utilities"); the Office of the Consumer Advocate ("OCA"); Clean Energy New Hampshire ("CENH"); Conservation Law Foundation ("CLF"); Granite State Hydropower Association; Standard Power of America; and Walmart Inc. (collectively, the "Settling Parties") hereby submit this reply brief to the New Hampshire Public Utilities Commission (the "Commission") to respond to certain assertions made by the New Hampshire Department of Energy ("DOE or "Department") and the Community Power Coalition of New Hampshire ("CPCNH") in their respective initial briefs. In support of this brief, the Settling Parties state the following:

DOE BRIEF

I. The Proposed Legacy Period for Newly Enrolled Net Metering Projects is a Reasonable Measure for Maintaining the Viability of Net Metering

The Settling Parties agreed that NEM 2.1 should include a "Legacy Period" to support the economic viability of newly enrolled net metering projects and, more broadly, the stability of net energy metering in New Hampshire. Docket No. DE 22-060, Settlement at 3-4, Appendix B. The Legacy Period ensures "any NEM project that first commences receiving NEM compensation under the NEM 2.1 tariff will be eligible to continue to receive the NEM 2.1 tariff for 20 years from the year in which it first begins net metering," and thus provide the certainty necessary to invest in and, in many cases, finance such projects. The Commission previously approved a similar "grandfathering" period of up to twenty-three (23) years, with a sunset date of December 31, 2024. Docket No. DE 16-576, Order 26,029 at 51 (June 23, 2017).

The DOE recommends that the Commission maintain the current alternative net metering tariff (NEM 2.0) while also maintaining the sunset date of December 31, 2040, as first established more than seven years ago in Docket No. DE 16-176. In other words, a project enrolling in 2025 would have certainty as to the applicable compensation structure for fifteen years or less, whereas a project that enrolled in 2018 had more than two decades of certainty. A project enrolling in 2026 will only have fourteen years of assurance. Notwithstanding the concerns raised by the Department in its brief, which the Settling Parties address below, simply maintaining the existing legacy period with a sunset date of December 31, 2024 will have an obvious and prejudicial effect upon the feasibility of individual Distributed Generation ("DG") projects as well as the DG industry in New Hampshire.

In support of its recommendation, the DOE first argues that the Settling Parties' proposal to revisit the net metering tariff after a data collection effort should preclude application of a twenty-year legacy period for newly enrolled projects. Accepting this argument will bring increasing uncertainty and instability to New Hampshire's DG industry, and inevitably cause many projects to be uneconomic. If the Settlement Agreement is approved, the Electric Utilities will undertake an 18-month data collection effort and stakeholder process and subsequently propose a NEM time-of-use rate ("TOU") two years from the date of Commission approval. Hypothetically, if the Commission were to issue an Order in this case on December 1, 2024, the Electric Utilities would file their proposed NEM TOU rate on or before December 1, 2026.

Given that the instant docket has been pending for more than two years, it is reasonable to expect that the Electric Utilities' proposal, and any other NEM tariff matters that are raised in the docket, will take at least a year if not longer to adjudicate. As such, it is reasonable to expect that a new net metering tariff would not take effect until 2028, if not later. At that point, projects will have only twelve years of assurance as to the applicable net metering compensation, a far cry from the twenty-three years adopted in 2017. Every year that passes places increased pressure on the economics of these projects.

The DOE's suggestion that new net metering customers will "lock" into the current compensation for twenty years is not accurate. The Settlement Agreement clearly contemplates that "[a]t any time during the Legacy Period, [a] project may elect to transfer to the tariff in effect at the time." Settlement at 3. So, while it may be true that NEM projects that enroll following an order approving the Settlement Agreement in this docket would have the option to remain on the tariff recommended by the Settlement Agreement for the next 20 years, it is in no way mandatory, as any project subject to the Legacy Period also has the option to transfer to subsequent tariffs and may not transfer back if they do. More importantly, because pursuant to the Settlement Agreement, NEM 2.1 would only apply to those customers that begin net metering between approval of the Settlement Agreement and issuance of a Commission order in the subsequent docket called for in the Settlement Agreement, the Legacy Period would be limited to the relatively narrow subset of NEM customers that begin net metering during a three- to four-year period.

The DOE also argues, rather vaguely, that "[t]here are . . . significant statutory developments in the past couple of years that impact the net metering ecosystem" and "have the potential to significantly impact net metering in New Hampshire," but acknowledges it "ha[s] yet to experience a full understanding of their impacts." DOE Initial Brief at 8. The DOE believes its lack of understanding militates in favor of maintaining the 2040 sunset date, though it offers no evidence or even hypothetical examples of how, in light of these "developments," compensation under NEM 2.1 would become "too high relative to the benefits provided." One statutory development mentioned by the DOE is the "expansion of net metering eligibility to 1-5 MW facilities as municipal hosts." *Id.* However, because net metering eligibility for 1-5 MW facilities is, by design, restricted only to "municipal hosts,"[1] which has a limited pool of eligible group members, net metering for 1-5 MW facilities is unlikely to expand in the next few years to such a degree as to "impact the net metering ecosystem" or result in cost shifts to non-net metering customers. There simply is not enough structure or substance to the Department's arguments regarding the potential new tariffs or statutory developments to justify a denial of the Legacy Period component of the Settlement.

There is evidence in the record and Commission precedent demonstrating that the current net metering tariff, which will continue under NEM 2.1, balances the interests of customer-generators and non-net metering customers, and does not result in unjust or unreasonable cost shifts. See, e.g., Joint Testimony of the Electric Utilities, Exhibit 2 at Bates Pages 10-11; see also Docket No. DE 16-576, Order 26,029 at 67, 71-72 (June 23, 2017) ("We find that the new net metering tariff provisions we have approved . . . are just and reasonable and serve the public interest."). At the hearing, the Department acknowledged that it performed no analysis

[1] Under New Hampshire law, "municipal host" is defined as 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 consisting exclusively of one or more customers who are political subdivisions, provided that all customers are located within the same utility franchise service territory. A municipal host may be owned by either a public or private entity. For this definition, 'political subdivision' means the state of New Hampshire or any city, town, county, school district, chartered public school, village district, school administrative unit, or any district or entity created for a special purpose administered or funded by any of the above-named governmental units. RSA 362 A:1-a, II-c.

demonstrating that the proposed twenty-year Legacy Period is unjust or unreasonable. Tr. 68:14-23 (August 22, 2024). The Department also acknowledged that a continually decreasing legacy period creates uncertainty for interconnectors. Tr. 62:10-14 (August 22, 2024).[2] The Legacy Period, which can be revisited when the Electric Utilities file a NEM TOU proposal two years from approval of the Settlement Agreement, is a reasonable measure with support in the record for ensuring that new projects have the benefit of economic certainty when planning and interconnecting projects in the intervening years.

Attachment B to the Settlement Agreement illustrates the economic impact of maintaining the 2040 sunset date versus implementing the Legacy Period until the next net metering docket. The attachment shows that the economic case for DG projects will likely soon become untenable if the 2040 sunset date remains in place, whereas the Legacy Period will allow for modest returns. Settlement Agreement, Attachment B, Exhibit 1 at Bates Page 3. The DOE expresses skepticism regarding the scenarios set forth in Attachment B, believing them to contain "unrealistic assumptions." Department Brief at 8. Contrary to the Department's assertion, the illustrations in Attachment B assume only that the 2040 sunset date remains in effect (Scenarios 1-4) or that the Legacy Period is adopted (Scenarios 5-6). A DG project developer can only rely on what is assured under the tariff; it cannot make assumptions regarding what may or may not change several years in the future, and gamble on whether such changes, if they occur, will be beneficial or detrimental to the project. This common-sense principle is actually supported by statements made by the DOE witnesses at hearing, during which they acknowledged that it was only a matter of opinion, unsubstantiated by evidence, that there would be a net metering tariff

[2] Q. [Krakoff] So you would . . . agree that having a continually decreasing legacy period creates uncertainty for interconnectors?
A. [Perruccio] Yes.

available after 2040, and that the Department does not (and cannot) forecast wholesale market revenue for customer-generators after 2040. The analysis in Attachment B is conservative in its assumptions, as it must be, and is therefore sound.

The arguments put forth by the Department also ignore testimony that the proposed Legacy Period is critical to financing NEM projects:

> [T]he legacy period is essential to stabilize the net energy metering market and the distributed energy market. . . . The reason it's essential is because these projects need to be financed. Whether they're going in as community power -- you heard some testimony on that before -- whether they are going in for municipality, they need third-party financing, and you can't get third-party financing when you're -- you're looking at 15 – certainly, you can't get it at 10 years. So it's essential. . . . [T]his is simply allowing for the financeability of the projects at a quite low after-tax rate of return.

Tr. 135:11-13; 136:3-15 (August 20, 2024) (Witness David Littell); see also Settlement Attachment A, Exhibit 1 at Bates 23 ("The purpose of this 20-year NEM proposed term is to provide adequate and stable customer expectations that allow for project financing. . . . If there is a risk that NEM qualifications or payment will vary in the future, it can present commercial and transactional risk issues that are not supportive of competitive distributed resource markets in New Hampshire."). The Department's proposed strategy of maintaining the existing 2040 sunset date will put these projects at risk, despite there being no evidence in the record that the current metering tariff – which is conservative relative to other New England states, Tr. 136:17-19 (August 20, 2024) – will result in unreasonable or unjust cost shifting.

Finally, the DOE speculates that implementing the Legacy Period may create administrative burdens or costs for the Electric Utilities. As proposed in the Settlement Agreement, the Electric Utilities will not be required to track the Legacy Period on a project-by-project basis from the date each project interconnects. Rather, the Legacy Period will be administered on an annual basis at the start of each calendar year, at which time any projects for which the Legacy Period has expired will be moved to the net metering tariff in effect at the time, if indeed such a tariff is in effect. This is a simplified approach that the Electric Utilities, as Settling Parties, have agreed to implement on the basis that retiring DG projects from the Legacy Period once annually based on vintage year would be possible without incurring incremental costs to administer. The DOE's concerns regarding administrative burdens and costs are appreciated but the Settling Parties believe the straightforward and simple approach proposed in the Settlement Agreement is reasonable and appropriate.

CPCNH BRIEF

I. CPCNH's Proposal to Remove the RPS Compliance Cost from DG Compensation is Unsupported by the Law and the Factual Record.

CPCNH proposes to eliminate the RPS compliance cost from inclusion in the net metering compensation tariff.[3] However, elimination of this component from the net metering tariff is unsupported by the law and by the record evidence for several reasons. First, although CPCNH proposes eliminating the RPS compliance cost from the tariff for *all* net metering customers, RSA 362-A:9 (XXIII), which directs the Commission to open a proceeding to adopt new net metering tariffs for systems over 1 MW, states:

> *[S]uch consideration of net metering tariffs that apply to newly-constructed customer-generators with a total peak generating capacity of greater than one megawatt* shall include but not be limited to whether or not the cost of compliance with the electric renewable portfolio standard . . . should be excluded from the monetary credit for exports to the grid.

Id. (emphasis added). Thus, RSA 362-A:9 (XXIII) limits consideration of compensation for RPS compliance to newly-constructed systems over 1 MW only, and consideration of the RPS

[3] *See* CPCNH Initial Brief, at 16-18.

compliance for systems under 1 MW is, as a matter of statutory law, beyond the scope of this docket.[4]

Second, CPCNH's claim that inclusion of the RPS compliance cost for DG compensation results in unjust and unreasonable cost shifting is speculative and unsupported by the evidence in the record.[5] As demonstrated by the Settling Parties' pre-filed rebuttal testimony and testimony at the hearing, the RPS compliance cost component of DG compensation equates to significantly less than $.01 per kWh and, therefore, "removing the RPS adde[r] from the net metering credit would be a negligible change to compensation, but would add significant complexity to compensation administration and to customers understanding their bills."[6]

The Settling Parties also explained that when reviewing whether unreasonable and unjust cost shifting is occurring, it is important to look at the overall compensation rate, instead of only individual compensation components.[7] CPCNH's own testimony and responses to the Commission's record requests belie CPCNH's claims regarding cost shifting and demonstrate that the overall compensation rate is just and reasonable. For example, CPCNH stated that, although compensating customer generators at the full default service rate "is in and of itself over-compensation for this rate component, for customer generators > 100 kW, **it still represents overall under-compensation for value produced**."[8] According to CPCNH, this is because "there is no credit for actual avoided transmission charges, which . . . is typically more

[4] DOE agrees that under RSA 362-A:9, XXIII consideration of the RPS compliance cost by the Commission is intended to be limited to systems over 1 MW. Ex. 7, Pre-Filed Testimony of DOE, at Bates 14-16.
[5] Hearing Transcript, Aug. 22, 2024, at 135-36.
[6] Ex. 3, Pre-Filed Rebuttal Testimony of Electric Utilities at Bates 18; *see also* Hearing Transcript, Aug. 20, 2024, at 133-34; Hearing Transcript, Aug. 22, 2024, at 216-17.
[7] Hearing Transcript, Aug. 20, 2024, at 133-34; Hearing Transcript, Aug. 22, 2024, at 216-17.
[8] Ex. 32, CPCNH Response to Commission Record Request Set 1, at Bates 10 (emphasis in original).

than the difference between the full default service rate and the base default service rate."[9] Thus, CPCNH admits that the *overall* compensation rate for customer generators > 100 kW is not resulting in unjust or unreasonable cost shifting.[10]

CPCNH's claim that compensating customer generators at the full default service rate will result in unjust and unreasonable cost shifting is also speculative. CPCNH's claim is largely based on the possibility that New Hampshire may one day increase its RPS requirements, which could increase the RPS compliance cost and, in turn, possibly result in increased cost shifts.[11] Because CPCNH's claim is based on an event that may or may not happen sometime in the future, the Commission should decline to rely on CPCNH's speculative evidence in reaching its decision in this matter. To the extent that RPS requirements change sometime in the future, the Commission will have the opportunity to reassess any potential cost shifts when they occur. Indeed, the Settlement Agreement includes a provision requesting that the Commission open a subsequent docket to consider net metering tariffs in two years, which will provide the Commission with the opportunity to revisit potential cost shifting in just a few years, including any potential cost shifts resulting from changes to New Hampshire law.

Finally, CPCNH's claim that customer generators should not receive the full default service rate because they do not contribute to the RPS compliance obligation is contradicted by the evidence in the record.[12] Under New Hampshire law, customer generators that do not obtain

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[9] *Id. See also* Hearing Transcript, Aug. 22, 2024, at 133 (with CPCNH stating that "for over 100 kW today, it's not a net cost shift, because of the lack of compensation for avoided transmission costs. So just getting the full default service rate is still undercompensating compared to the value produced").

[10] Based on this representation, one can infer that CPCNH only supports the Commission removing the RPS compliance cost from compensation for customer generators > 100 kW, if the Commission concurrently also augments the compensation rate so that these customer generators can receive credit for actual avoided transmission charges. With respect to customer generators < 100 kW, CPCNH testified that the compensation rate is "pretty close to about right" and "doesn't have the risk of being an excessive and undue cost shift," because it's a smaller order of magnitude. Hearing Transcript, Aug. 22, 2024, at 137-38, 196.

[11] Hearing Transcript, Aug. 22, 2024, at 135-36; CPCNH Initial Brief, at 18.

[12] *See* CPCNH Initial Brief, at 17-18.

RECs provide value with respect to the Electric Utilities' RPS compliance obligations. This is because, pursuant to RSA 362:F:6 (II-a), in a process known as "REC sweeping," the DOE annually estimates the amount of photovoltaic production from NH systems that do not produce RECs, and allocates such REC equivalencies to the Electric Utilities to use in satisfying their RPS compliance obligation.[13] In other words, net metering customers that do not produce RECs help reduce the Electric Utilities' RPS compliance costs. In fact, most customer generators with systems under 100 MW do not receive or produce RECs.[14] Accordingly, as established by the evidence of record, compensating customer generators with the full default service rate is justified because it serves as a way to compensate customer generators for the value they provide in helping reduce the costs of the Electric Utilities' RPS compliance obligations.[15]

II. Developing a Capacity Credit for Customers Being Served by CPAs and Competitive Suppliers is Outside the Scope of this Docket and no Evidence Has Been Presented that the Issue is Within the Purview of the Commission's Rate-Making Authority.

CPCNH proposes in its initial brief that the Commission order the Electric Utilities to convene a stakeholder group so that "customers of suppliers other than the utility can receive credit" for avoided capacity costs and that the Electric Utilities and other parties may file proposals for such a credit, after which "the Commission may issue a supplemental order of notice for additional process needed to determine how, when, and to what extent to implement

[13] Ex. 3, Pre-Filed Rebuttal Testimony of Eversource at Bates 17; Ex. 17, CPCNH Response to Eversource Data Request 1.4, at Bates 1-2; Ex. 32, CPCNH Response to Commission Record Request Set 1, at Bates 10; Hearing Transcript, Aug. 22, 2024, at 217-18.
[14] Ex. 32, CPCNH Response to Commission Record Request Set 1, at Bates 10; Hearing Transcript, Aug. 22, 2024, at 138, 217-18.
[15] Hearing Transcript, Aug. 22, 2024, at 138, 217-18; Ex. 32, CPCNH Response to Commission Record Request Set 1, at Bates 10; Ex. 17, CPCNH Response to Eversource Data Request 1.4, at Bates 1-2; Ex. 3, Pre-Filed Rebuttal Testimony of Eversource at Bates 17. CPCNH acknowledges in its testimony and responses to discovery requests that net metering customers that do not produce RECs provide value with respect to the utilities' RPS compliance obligations. Hearing Transcript, Aug. 22, 2024, at 138; Ex. 17, CPCNH Response to Eversource Data Request 1.4, at Bates 1-2; Ex. 32, CPCNH Response to Commission Record Request Set 1, at Bates 10.

credit for avoided capacity costs".[16] Taking such action would be squarely outside the scope of this docket, which is to evaluate the existing *utility NEM tariff*, including customer compensation (under that tariff). Developing a credit for customers on competitive supply and CPA service was not noticed in this docket. Further, the Commission regulates the Electric Utilities as well as the rate for net metering compensation, but that does not extend to developing credits for entities outside the regulated community. CPAs and competitive suppliers are regulated to a limited extent,[17] but are not subject to the plenary authority of the Commission, including the authority of the Commission to set rates. It follows, then, that it would be outside the Commission's authority to order the Electric Utilities to develop a credit rate for customers of CPAs and competitive suppliers, and for the Commission to consider proposals and subsequently authorize and implement such a credit. Neither CPCNH's testimony nor its initial brief cite to any authority that creates a regulatory path for the Commission to take such action on behalf of CPA and competitive supplier customers.[18] CPCNH's brief even states on page 10 that "RSA 362-A:9, II and [*sic*] now includes Community Power Aggregations (CPAs) under RSA 53-E along with Competitive Electricity Power Suppliers (CEPS) as having the right to serve NM customers *and determine the prices at which they agree to supply and credit or purchase output exported to the grid.*" By CPCNH's own logic, it is the responsibility of CPCNH, and not the Commission, to set the rates for charges and credits to its customers.

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[16] CPCNH initial brief at 19.

[17] Certain CPA actions are governed by the Puc 2200 rules, and those of competitive suppliers by the Puc 2000 rules.

[18] The CPCNH brief cites to the "same arguments and evidence concerning the need to enable a level playing field between utility default service NM and NM programs provided by CPAs and CEPS with regard to credit to large CGs that can create avoided transmission costs" applies to developing a capacity credit for these customers, but this misunderstands the scope of RSA 374-F. The Settling Parties will not argue the purpose of the Electric Restructuring Act in this brief, but regardless the overarching purpose of the Act, nothing in that statute or any other creates an affirmative obligation to credit customers of CPAs and competitive suppliers or gives the Commission authority to set rates (including credit rates) for non-regulated entities.

But even if the topic were within the scope of the docket and under the Commission's purview, what little is in the record regarding the development of a capacity credit creates doubt that pursuing such a credit would be in the public interest. CPCNH argues that the implementation of a CPA/competitive supplier capacity credit would necessarily require the overhaul of utility load settlement as suggested by CPCNH in its testimony.[19] For the reasons stated in the Settling Parties' initial brief, and as detailed further below, modifying the load settlement process is also outside the scope of the docket and it is dubious that the costs of such an undertaking would be in the public interest.[20] Neither existing law and regulation, nor the scope of this docket, allow for the adoption of CPCNH's recommendation for the development of its desired capacity credit for CPA and competitive supply customers. But even if the Commission had authority to do so, the record is insufficient to support the Commission directing the Electric Utilities to develop such a credit.

III. CPCNH's Argument in Support of Modifying Load Settlement is Flawed, as it Relies on Erroneous Premises, and Load Settlement Remains Outside the Scope of this Docket.

As a primary issue, the Settling Parties reiterate their assertion from the Electric Utilities' rebuttal testimony and the Settling Parties' initial brief: modifying load settlement is outside the scope of this docket, and the record does not support taking such action.[21] Additionally, CPCNH's brief relies on CPCNH testimony that asserts modifying load settlement by accounting for NEM exports to the grid as an offset to the default service load obligation would decrease the

[19] Exhibit 13, Testimony of CPCNH at Bates Page 23. CPCNH also refers to the need for either interval meters, specialized load settlement profiles, or both, and both would incur considerable incremental costs, as the Electric Utilities have testified to. Exhibit 3, Joint Rebuttal Testimony of the Electric Utilities at Bates Pages 23-27.
[20] Initial brief of the Settling Parties at 9-10.
[21] Exhibit 3 at Bates Page 26; Settling Parties initial brief at 9-10.

cost of default service in proportion to the amount of NM exports. CPCNH Initial Brief at 9. The record evidence demonstrates that this is untrue. Eversource witness Joe Swift testified that what CPCNH envisions for modifying load settlement cannot result in a one-for-one deduction to the utility default service load or the load of any other supplier or CPA, but rather would only result in a reduction totaling the delta between the amount a supplier exports over other suppliers.[22] There are no net savings; it is simply a cost shift among suppliers, and a small one at that.

CPCNH's assertion in its initial brief that the Commission has a mandatory, affirmative duty to order the Electric Utilities to modify load settlement is also clear error. The CPCNH brief cites to RSA 362-A:9, II, which states "[s]uch output shall be accounted for as a reduction to the customer-generators' electricity supplier's wholesale load obligation for energy supply as a load service entity, net of any applicable line loss adjustments, ***as approved by the commission***" (emphasis added). The only way to interpret an unqualified mandatory duty of the Commission is to not read to the end of the statute. The output shall *only* be accounted for as a reduction to a supplier's load obligation *as approved by the Commission*, and Commission approvals must contain a finding that whatever it is approving is just, reasonable, and in the public interest. The statutory language cited to by CPCNH does not nullify that duty.

CPCNH's assertion on page 10 of its brief that "Maximally modernizing load settlement simultaneously amounts to taking the largest step possible to minimize undue cost shifting and making much more transparent the costs and benefits of NM" is supported only by a general reference to the CPCNH direct and rebuttal testimony, and as discussed above, the premises of that testimony have been directly refuted by the Electric Utility witnesses at the hearing on

[22] Hearing Transcript, Aug. 22, 2024, at 232, line 17 through 236, line 8.

August 22, 2024. This falls far short of a sufficient level of evidence to support an undertaking of such scale. Additionally, CPCNH asserts that customer generators must be used and accounted for in load settlement as load reducers to maximize value and avoid cost shifting. However, in footnote 19 on page 9 of CPCNH's initial brief, they state that only 51 of 16,400 customer-generators are ISO-NE market participants. Approximately 80 percent of the 51 customer-generators are small hydroelectric group hosts. The Dunsky VDER study found that "[u]nlike all other system types, micro hydro facilities generate greater value to the system by directly participating in the wholesale energy and capacity markets rather than by just passively reducing load." Dunsky VDER Study, Exhibit 8, Bates Page 54. Therefore, the vast majority of the customer-generators currently participating in the ISO NE markets are maximizing their "value to the system" and therefore their value to ratepayers, including those ratepayers not participating in net metering under the status quo. Based on the record evidence, these customer generators should not be required to withdraw from ISO-NE markets or be penalized for continued participation as is proposed by CPCNH in Section X of their brief.

Lastly, CPCNH's assertion that the existing load settlement process is conferring an unfair advantage on the Electric Utilities is misplaced. First, New Hampshire's NEM program, as prescribed by statute and prior Commission orders, is not "perpetuating monopolies", as asserted by CPCNH. The Electric Utilities do not profit or generate revenue off NEM, they simply recover their costs of administering the program. It would be a violation of RSA 362-A:9, as well as an unreasonable and an unconstitutional taking to require the Electric Utilities to bear the cost of administering NEM without any recovery of those costs. And if there is a duty of the Commission to "foster competition" as asserted by CPCNH, and on which the Settling Parties will not comment in this brief, any such duty would not be unfettered, but subject to a finding that any action to foster competition was just, reasonable and in the public interest. As discussed in the Electric Utilities rebuttal testimony and at the hearing on August 22, 2024, changing load settlement is a significant investment, the full extent of which is unknown because not enough is known about what CPCNH would like to do with it, and the benefits have not been sufficiently quantified in the record to justify pursuing this action, through a stakeholder process or otherwise. Given the record evidence, there is just as much possibility that the cost of changing load settlement creates a cost shift, rather than preventing one, since there are no net savings, just cost shifting among suppliers, as mentioned above and at the August 24 hearing.[23] Under these circumstances, and because modifying load settlement is not a noticed issue in this docket, the Commission must not order such a course of action.

IV. Implementation of a Transmission Credit as Proposed by CPCNH is Both Contested and Insufficiently Supported by the Record

CPCNH argues that the Commission is obligated to approve a transmission credit for large customer generators in this docket based on the statutory language that that the "commission, through an adjudicative proceeding, shall continue to develop and periodically review new alternative net metering tariffs." RSA 362-A:9, XVI(a). While the Commission certainly has the authority to investigate and, if found to be appropriate, approve a transmission credit, the Settling Parties urge the Commission to recognize (1) that the statute does not mandate approval of a transmission credit in this docket, and (2) that approval would be inappropriate here because CPCNH has not presented sufficiently specific proposals to the Commission for review, and such proposals would need to be, and have not been, thoroughly

[23] *See* FN 21.

analyzed and vetted to ensure the roll out of a transmission credit is feasible, cost effective, likely to achieve its intended goals, and otherwise in the public interest.

First, a statutory directive to "continue to develop and periodically review" the Electric Utilities' net metering tariffs is not a directive to approve a specific transmission credit. The language recognizes that net metering tariffs evolve over time; the obligation is for the Commission to "continue" that process. The language does not set a timeline, does not list specific components of a net metering tariff that must be approved, and, most important, the statute does not relieve the Commission of its obligation to find, based on the evidence in the record, that a new transmission credit would be just, reasonable, and in the public interest. CPCNH's interpretation that the statute mandates Commission approval of a transmission credit is without merit. Mandatory expansion of compensation, eligibility, and scope would circumvent the Commission's core responsibility to find such expansions to be reasonable.

Second, there is not a sufficient record, and there has not been sufficient review and vetting of a transmission credit on which the Commission could make a finding as to whether it would be just, reasonable and in the public interest.

In its brief, CPCNH continues to reference singular utility-owned DG projects in support of its argument that customer-generators should be compensated for avoided transmission charges. While the records in the dockets cited by CPCNH demonstrate that there are avoided transmission cost benefits associated with the utility-owned projects that accrue to the advantage of customers, there is no evidence or analysis produced by CPCNH or otherwise in the record demonstrating that the Commission can just take, for example, a net benefits analysis associated with a specific utility-scale project and then simply extrapolate that analysis into a broad-based credit to compensate customer-generators.

There has been no evidence demonstrating whether, and to what extent the transmission value of those utility projects would translate statewide if implemented through a net metering transmission credit. The complexity and likely burdensome undertaking to implement CPCNH's nebulous proposal of a bespoke transmission rates have not been vetted, nor is there sufficient record evidence for the Commission to know the extent of the effort and costs that would be necessary to implement such a credit. And adding CPCNH's suggested transmission credit to existing NEM compensation also expands total NEM costs, the nature and extent of which have not been explored.

Therefore, there is not sufficiently conclusive record evidence to support a Commission finding that implementation of transmission credits for large customers at this time would be just, reasonable, and in the public interest.

CONCLUSION

For all the foregoing reasons, the recommendations by DOE and CPCNH addressed in this brief should not be adopted by the Commission, and the Settling Parties respectfully reiterate their request that the Commission take the actions recommended in the initial brief of the Settling Parties. The Settling Parties appreciate the Commission's thoughtful deliberation throughout these proceedings and the consideration of these briefs.

Respectfully submitted,

Public Service Company of New Hampshire d/b/a Eversource Energy; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty; Unitil Energy Systems, Inc.; the Office of the Consumer Advocate; Clean Energy New Hampshire; Conservation Law Foundation; Granite State Hydropower Association; Standard Power of America; and Walmart Inc.

CERTIFICATE OF SERVICE

I hereby certify that, on the date written below, I caused the attached to be served pursuant to N.H. Code Admin. Rule Puc 203.11.

10/18/2024	
Date	Jessica A. Chiavara