STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Potential Jurisdictional Conflicts Related to	)	
Authorization of Pilot Programs Under RSA	)	DE 23-026
362-A:2-b	)	

REPLY BRIEF OF THE JOINT UTILITIES

July 10, 2023

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Pursuant to the May 16, 2023 Prehearing Order of the New Hampshire Public Utilities Commission ("Commission"), Public Service Company of New Hampshire d/b/a/ Eversource Energy ("PSNH"), Liberty Utilities (Granite State Electric) Corp. d/b/a/ Liberty ("Liberty"), and Unitil Energy Systems, Inc. ("UES") (collectively, the "Joint Utilities"), submit this joint Reply Brief in the above-referenced docket. The Joint Utilities respond to the arguments submitted in the Initial Briefs of the Community Power Coalition of New Hampshire ("CPCNH I.B.")[1] and the Office of Consumer Advocate ("OCA I.B.").

I. INTRODUCTION

The CPCNH and OCA Initial Briefs include a wide array of irrelevant arguments in defense of the position that the Commission should make no findings of preemption with regard to the provisions of RSA 362-A:2-b (the "LEEP Act"). Both briefs ignore the fact that the statute at issue is so vague that the word choices alone cause preemption issues to arise. In the Sections below, the Joint Utilities explain how the arguments

[1] Citations are to the corrected CPCNH Initial Brief submitted on June 26, 2023.

presented by CPCNH and OCA do not undermine the Joint Utilities' positions on preemption, and in several cases, confirm their stated concerns.

II. THE JOINT UTILITIES CANNOT ACCOMMODATE INTRASTATE WHOLESALE SALES ON THEIR TRANSMISSION OR DISTRIBUTION FACILITIES (JOINT UTILITIES I.B. 7-14)

OCA and CPCNH complicate a straightforward jurisdictional analysis, trying to convince the Commission that *CPUC*,[2] which addressed the issue of distributed energy resources ("DERs") making wholesale sales to local customers, was decided erroneously or is no longer valid. And both parties put forth arguments based on cases that are wholly irrelevant to this simple jurisdictional issue. They misconstrue: (1) Federal Energy Regulatory Commission ("FERC") jurisdiction over wholesale sales in interstate commerce; (2) net metering jurisdiction; (3) exemptions to exclusive federal jurisdiction, such as under the Public Utility Regulatory Policies Act of 1978 ("PURPA"); 4) FERC's jurisdiction over generation; and 5) FERC's interconnection jurisdiction, all in their attempt to defend the concept of "intrastate" wholesale sales. In sum, both parties fail to produce *any* evidence that FERC permits a state to regulate a wholesale sale (in a location other than Alaska, Hawaii, or ERCOT) on the grounds that the sale is in intrastate commerce.

A. Academic opinions are not evidence of FERC recognizing intrastate wholesale sales.

There are those who would prefer that FERC narrow its jurisdiction over wholesale sales by DERs. CPCNH points to scholarly articles as a reason that the

[2] *Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047 (2010) ("*CPUC*").

Commission should ignore clear precedent and instead recognize *intrastate* wholesale sales on the grounds that FERC's *CPUC* decision is outdated.[3]

At the time *CPUC* was issued, Frank Lindh served as General Counsel of the CPUC; thus, he was on the *losing* side of the case where FERC found wholesale sales to utilities under a feed-in-tariff by DERs were sales in *interstate* commerce and thus could *only* be compelled under PURPA. Shortly thereafter, he co-wrote a law review article acknowledging that the "contemporary characterization by the FERC has rendered virtually all sales and interconnections of generators exporting net production to the grid as beholden to federal regulation."[4] The article stated that, "[c]ontrary to the FERC's view, it is the *authors' opinion* that the states under the Federal Power Act actually retain full jurisdictional authority over wholesale sales of electric energy in intrastate commerce, to the extent such sales and deliveries occur on distribution circuits for local consumption."[5] Mr. Peskoe, another author cited by CPCNH, similarly acknowledges "FERC claims that energy sales by DERs are wholesale sales 'in interstate commerce' and therefore under its exclusive authority."[6] In short, the articles cited support the Joint Utilities' position on the current state of the law.

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[3] CPCNH I.B. at 14 & n.31.

[4] Frank R. Lindh & Thomas W. Bone, *State Jurisdiction Over Distributed Generators*, 34 Energy L.J. 499, 521 (2013).

[5] *Id*.

[6] Ari Peskoe, *The Case Against Direct FERC Regul. Of Distributed Energy Res.*, at 7 (Sept. 20, 2018).

A world in which *intrastate* wholesale sales may occur if such sales occur only on distribution circuits for local consumption would be a regulatory morass resulting in litigation purgatory. By simply placing sufficient DERs on a distribution circuit, electric energy can flow to or from the transmission system at any given second, based on load and output, assuming that there even is load on the same distribution circuit as the DER(s). In a rural state, where a DER is sited outside a load center on a circuit with few retail customers, the chance of two-way power flows increases. In this world, there would need to be a *constant* monitoring to determine where electrons were flowing to ensure that no electron supplied by a DER ever reached a transmission facility, as, if it did, any wholesale sale would become interstate in nature. This approach to jurisdiction is impractical and unworkable.

B. FERC's net metering policy does not create any gray area between federal and state jurisdiction.

Both OCA and CPCNH claim that net metering jurisdiction is so murky that it supports their position, despite the fact that the limited producer issues being briefed have *nothing* to do with net metering. OCA states:

> [I]n practice, intrastate wholesale markets are a grey area. For example, net metering is a wholesale transaction, which can fall under either state or FERC jurisdiction despite what the FPA lays out. However, FERC does not consider state net metering to intrude on its jurisdiction when there is no net sale over the billing period. *Sun Edison LLC*, 129 FERC

> ¶ 61,146 at 6 (2009); *MidAmerican Energy Company*, 94 FERC ¶ 61,340 at 62,262-63 (2001).[7]

CPCNH states even more boldly that:

> In examining jurisdictional issues, FERC has expressed uncertainty about its jurisdictional authority and recently has instead erred on the side of caution and allowed states to exercise jurisdiction over sales at wholesale within a given state.[8]

In support of its argument, CPCNH notes that FERC declined to weigh-in on legal questions raised in two "important cases," footnoting *NERA*[9] and presumably intending to footnote *Otter Creek Solar*.[10]

OCA's claim that "net metering is a wholesale transaction, which can fall under either state or FERC jurisdiction despite what the FPA lays out,"[11] is in error. Net metering involves three possible "situations": (1) a retail load of a retail net metering customer is being served by a resource located behind the retail customer's meter; (2) power is flowing out from a net metering customer's meter because there is more production than load and the retail customer is being credited by its utility on either a kWh or $/kWh credit basis for the excess energy flowing out; or (3) at the end of a

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[7] OCA I.B. at 3. Note that the OCA, in some cases, cites to FERC orders using the page number of the slip opinion, rather than the Paragraph number of the slip opinion or the CCH page number, which are the two more commonly used forms of FERC citations.

[8] CPCNH I.B. at 11.

[9] *New England Ratepayers Ass'n*, 172 FERC ¶ 61,042 (2020) ("*NERA*").

[10] *Otter Creek Solar LLC,* 143 FERC ¶ 61,282 (2013) ("*Otter Creek Solar*"). Although footnote 27 of the CPCNH I.B. cut off abruptly, the Joint Utilities believe that the second FERC "inaction" referred to was FERC's Notice of Intent Not to Act in Docket Nos. EL13-60-000 and QF13-402-001 (i.e., *Otter Creek*), discussed in footnote 29 of the CPCNH Initial Brief.

[11] OCA I.B. at 3.

period, a retail net metering customer is being paid in cash, not credit, for net excess power produced. Situation 1 is either self-provision or a retail sale, depending on who owns the supplying resource, and does not involve *wholesale* sales at all. Thus, net metering is not *always* a wholesale transaction, as OCA states. Situation 3 was explicitly found in the cited *Sun Edison* case to be a wholesale sale in interstate commerce that might be exempt from FERC rate regulation under PURPA.[12]

That leaves Situation 2, a form of exchange, which the New England Ratepayers Association sought to have declared a wholesale sale in interstate commerce.[13] FERC declined to do so, by dismissing the petition.[14] But does that mean Situation 2 is a wholesale sale in *intrastate* commerce? Not at all. In *Sun Edison*, FERC clearly stated that, "under the holding of *MidAmerican*, where there is no net sale over the applicable billing period to the local load-serving utility, *there is no sale*."[15] If there is any doubt

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[12] *Sun Edison LLC,* 129 FERC ¶ 61,146 at P 18 ("*Sun Edison"*) (holding that "[o]nly if the end-use customer participating in the net metering program produces more energy than it needs over the applicable billing period, and thus is considered to have made a net sale of energy to a utility over the applicable billing period, has the Commission asserted jurisdiction. If the entity making a net sale is a QF that has been exempted from section 205 of the FPA by section 292.601 of our regulations, no filing under the FPA is necessary to permit the net sale; however, if the entity is either not a QF or is a QF that is not exempted from section 205 of the FPA by section 292.601 of our regulations, a filing under the FPA is necessary to permit the sale.") (citations omitted).

[13] *NERA,* 172 FERC ¶ 61,042 at P 2 ("NERA asks the Commission to declare that it has jurisdiction over energy sales from rooftop solar facilities and other distributed generation located on the customer side of the retail meter (1) whenever the output of such generators exceeds the customer's demand . . . .").

[14] *Id.* P 35.

[15] *Sun Edison*, 129 FERC ¶ 61,146 at P 19.

that Situation 2 involves no sale, years after *Sun Edison*, in *CAISO,*[16] the Commission clarified for the "California Utilities" that the *Sun Edison* "no sale at all" finding remained good law.

CAISO arose because the "California Utilities" became concerned that FERC had stated in an order that sales by net metering customers (to utilities) were not subject to FERC jurisdiction – implying that such sales might be intrastate sales. The California Utilities explained to FERC that "*Sun Edison* did not hold that sales by net metering customers are not subject to the Commission's jurisdiction[, but instead] held that certain types of exchanges (i.e. credits) between utilities and net metering customers were not sales at all."[17] They told FERC that "[a] non-sale and a non-jurisdictional wholesale sale (i.e., a Federal Power Act ("FPA")-exempt wholesale sale) are entirely different concepts."[18] They explained that they sought clarification because:

> [I]t is important that *Sun Edison* and *CPUC* remain valid FERC policy. If modified or overturned, wholesale *sales* (except for those under FPA/PURPA-authorized exemptions) may no longer be subject to FERC jurisdiction, which could result in potential jurisdictional chaos.[19]

FERC granted the requested clarification, indicating that the *Sun Edison* holding (of no sale) was not reversed or modified.[20]

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[16] *Cal. Indep. Sys. Operator Corp.,* 181 FERC ¶ 61,035 (2022) ("*CAISO*").

[17] *Id.* P 7.

[18] *Cal. Indep. Sys. Operator Corp.*, Petition for Clarification of S. Cal. Edison Co., Pac. Gas & Elec. Co., & San Diego Gas & Elec. Co., FERC Docket. No. ER21-2455-002, at 2 (filed July 15, 2022).

[19] *Id.* at 4 (citation omitted).

[20] *CAISO*, 181 FERC ¶ 61,035 at P 8.

In sum, *Sun Edison*, as reaffirmed in *CAISO*, cleared away *any* potential gray area, finding that net metering involves one of the following depending on the given situation: a retail sale, no sale, or a wholesale sale in interstate commerce.

C. PURPA does not create any gray jurisdictional area with regard to wholesale sales.

CPCNH pointed not only to a net metering case, but also to *Otter Creek Solar* as support for its claim that FERC has expressed uncertainty and has allowed states to exercise jurisdiction over sales at wholesale within a given state. *Otter Creek Solar* involved Vermont's Sustainably Priced Energy Enterprise Development ("SPEED") program, which involves voluntary purchases from smaller qualifying facilities ("QFs") under PURPA's FPA rate exemption.[21] FERC, in declining to act, found that:

> Nothing in the Commission's regulations limits the authority of *either* an electric utility or a QF *to agree to rates* for any purchases or terms or conditions relating to any purchases which differ from the rates or terms or conditions which would otherwise be required by the Commission's regulations.[22]

In short, *Otter Creek* held that a voluntary program that pays rate-regulation exempt QFs higher than avoided cost is legally acceptable if not compelled. As the Joint Utilities already demonstrated in their Initial Brief (at 11-12), wholesale PURPA sales are wholesale sales in interstate commerce.[23]

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[21] FERC's PURPA regulations exempt sales from 20 MW and smaller QFs from rate regulation. 18 C.F.R. § 292.601 (2022).

[22] *Otter Creek Solar,* 143 FERC ¶ 61,282 at P 4 (emphasis added) (citation omitted).

[23] Indeed, the aforementioned regulation exempting such sales from rate regulation would not be needed otherwise.

D. The fact that an RTO may treat a wholesale sale as a "load reducer" for certain purposes does not mean it is not a wholesale sale in interstate commerce.

CPCNH proffers another theory in support of its claim that FERC "allowed states to exercise jurisdiction over sales at wholesale within a given state."[24] It points to *PTOs*, the case in which ISO-NE and its PTOs sought to change the denominator for the purpose of measuring Regional Network Load ("RNL") to exclude load served by non-registered DERs under 5 MW.[25] CPCNH explains:

> Under the ISO-NE OATT approved in the Commission's February 11, 2022 Order in Docket No. ER21-2337, distributed generation and distributed storage that are under 5 MW, interconnected to the distribution grid, and not registered as a generator with ISO NE (*i.e.* not participating in a FERC jurisdictional interstate wholesale market and not trying to sell across state lines) can function as a "load reducer" under ISO-NE operating procedures (OP-14).[26]

The fact that a load is not "counted" for transmission cost allocation purposes does not mean that the generator indirectly serving that load with energy, i.e., through a wholesale sale to a load-serving entity ("LSE"), is not making a wholesale power sale in interstate commerce. A seller can sell wholesale power without *anyone* being allocated transmission costs related to the delivery of that wholesale power because transmission and energy are unbundled products.

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[24] CPCNH I.B. at 11.

[25] *Participating Transmission Owners Administrative Comm.*, 178 FERC ¶ 61,086 (2022) ("*PTOs*").

[26] CPCNH I.B. at 12.

For example, in its compliance filing under Order No. 841 (DER Aggregation), the CAISO decided not to allocate *any* transmission charges to wholesale loads of storage resources when the CAISO delivered wholesale energy to charge such resources. FERC permitted that approach.[27] Thus, a storage resource in the CAISO control area may buy wholesale power from the CAISO market to charge its battery resource (at the locational marginal price), and pay no transmission charge at all, even though the CAISO normally assesses transmission charges on a kWh basis. Certainly, the wholesale sale being made to the battery resource through the CAISO market is a wholesale sale in interstate commerce. *Nothing* in the *PTOs* case supports the notion that FERC is altering its stance over wholesale sales when it is addressing transmission cost allocation. Transmission and power are separate products that are sold separately and their costs can be allocated separately.[28]

E. *EPSA* and *Hughes* are irrelevant when clear jurisdictional lines exist.

OCA's Initial Brief starts its discussion of jurisdiction with unremarkable comments about what the FPA states, but then indicates that *EPSA*[29] and Hughes[30] are "the legal landscape through which the Commission must navigate federal and state

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[27] *Cal. Indep. Sys. Operator Corp*., 169 FERC ¶ 61,126 at P 138 (2019) ("We find that CAISO has demonstrated that its proposal to exempt all electric storage resources from transmission access charges when charging is consistent with its existing rate structure, and thus is consistent with requirements of Order No. 841 . . . .").

[28] *E.g., So. Cal. Edison Co. v. FERC*, 603 F.3d 996, 1001-1002 (D.C. Cir. 2010).

[29] *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260 (2016) ("*EPSA*").

[30] *Hughes v. Talen Energy Mktg.*, 136 S. Ct. 1288 (2016) ("*Hughes*").

jurisdictional boundary issues."[31] The two cases cited, however, are not at all relevant as to whether a transmission sale or a sale for resale of electricity in interstate commerce has occurred. Rather, they are cases that explore the boundaries of matters that "affect" or "relate" to the two electric services over which FERC has explicit jurisdiction – transmission and electricity sales for resale in interstate commerce.

In *EPSA,* the Supreme Court upheld FERC Order No. 745, which required wholesale electricity market operators to compensate electricity users, or demand response providers, at the same rate as electricity generators, for users' commitment to reduce their electricity use during peak periods. In upholding FERC's authority to promulgate the order, the Court held that the practices regulated by Order No. 745 (relating to demand response) "directly affect wholesale rates,"[32] and so are within FERC authority under the FPA. In *Hughes*, at issue were Maryland's state-sponsored "contracts for differences" that required a generator to bid its energy and capacity into the wholesale market and provide a rebate if the market-clearing price was above the contract level. The fact that the state was nominally regulating something within its jurisdiction (that is, generation facilities) did not save the regulation from preemption where the state program disregarded an interstate wholesale rate required by FERC.[33] In contrast, the issue here involves wholesale power sales by limited producers, not financial contracts; wholesale

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[31] OCA I.B. at 3.

[32] *EPSA*, 577 U.S. at 276.

[33] *Hughes,* 136 S. Ct. at 1288.

power sales are not at the outer boundaries of the scope of FERC authority. The above cases therefore are not relevant.

OCA also states that "the [New Hampshire] statute authorizes *retail* customers to sell electricity to each other at distribution voltage – transactions devoid of the sort of tethering deemed impermissible under *Hughes*.[34] But the preemption concern raised by the Joint Utilities is that the limited producer *may* sell at *wholesale* to LSEs; if the statute at issue here did nothing more than allow retail customers to sell power to one another, then Initial Briefs would have been quite different.

CPCNH points to cases such as *EPSA* (Initial Brief at 15[35]) that state the obvious, that the states *do* have jurisdiction over wholesale sales in intrastate commerce. But, none of those cases discuss the substantive issue; the Joint Utilities concede that intrastate sales do occur in Hawaii, Alaska, and the ERCOT region of Texas. CPCNH draws inferences from opinions mentioning intrastate wholesale sales, or neglecting to use the "interstate" modifier, that are unsupported.

F. Interconnection and generation jurisdiction are wholly irrelevant to jurisdiction over wholesale sales in interstate commerce and actually demonstrate FERC's insistence on keeping the issues separate.

OCA raises the issue of jurisdiction over generation, which is not relevant to jurisdiction over wholesale sales. Both OCA and CPCNH discuss what is perhaps one of the most complex areas of jurisdiction – the interconnection of generation and storage

[34] OCA I.B. at 4 (emphasis added).

[35] Also citing *New York v. FERC*, 535 U.S. 1 (2002) and *Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 964 F.3d 1177 (D.C. Cir. 2020).

resources to distribution facilities where the resources intend to sell wholesale power. But FERC's jurisdiction, or lack thereof, over generation, and its complex DER interconnection jurisdiction, also are of no relevance to the topic at hand.

As to generation, OCA states:

> FERC has implicitly disclaimed jurisdiction regarding generation assets by only requiring those generation assets with a rated interconnection of 5 megawatts ("MW") or more to register with ISO-NE. *Participating Transmission Owners Administrative Committee* ["*PTOs*"], 178 FERC ¶ 61,086 at 17, and 21.[36]

FERC has virtually no jurisdiction over generation itself,[37] thus it did not disclaim jurisdiction over 5 MW or smaller generation in *PTOs*. That case does not stand for the proposition that generators 5 MW or larger are FERC-regulated, while smaller generators are not. The fact that ISO-NE requires 5 MW or larger generators to register with it has nothing to do with FERC jurisdiction over the generator; instead, it has to do with ISO-NE's transmission modeling requirements.[38] Moreover, generators owned by non-FERC-jurisdictional utilities, over which generation FERC basically has no jurisdiction beyond reliability standards, would have to register under the ISO-NE rule, so that ISO-NE can model and plan its system properly.

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[36] OCA I.B. at 10.

[37] FPA Section 201(b)(1) states that FERC "shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this Part and the Part next following, over facilities used for the generation of electric energy."

[38] *PTOs*, 178 FERC ¶ 61,086 at P 44 (explaining that load in transmission planning models is adjusted to account for the presence of demand resources and behind-the-meter solar PV, adding 5 MW or larger PVs and subtracting less than 5 MW PVs).

With regard to DER interconnection jurisdiction, OCA states:

> FERC has acknowledged how interconnection of distributed energy and storage programs could create uncertainty as to whether certain interconnections are subject to FERC or state/local jurisdictions and thus has explicitly left state interconnection procedures to state processes, so long as wholesale market issues are not implicated by state interconnection. *ISO New England Inc.*, 180 FERC ¶ 61,129, at 10-11 (2022) ["*ISO New England Inc.*"].[39]

CPCNH asserts "that interconnections to the distribution grid . . . are a matter for state jurisdictional authority and not a matter of interstate commerce subject to the jurisdiction of the [FERC]."[40] There is no initial citation to support this statement, but later in its Initial Brief, CPCNH claims that in *ISO New England Inc.*, FERC approved OATT revisions that *make clear* that the interconnection of distributed generation and storage is a purely state jurisdictional issue.[41]

Actually, in *ISO New England Inc.*, FERC granted a request by ISO-NE among other "Filing Parties" to *allow* the ISO-NE states to address all DER interconnections, *not merely ones over which the states already had jurisdiction*. They were seeking an *exception* from the situations in which, under Order Nos. 2003 and 2006, FERC *does* have jurisdiction over DER interconnections. Order Nos. 2003 and 2006 "adopted

[39] OCA I.B. at 10.

[40] CPCNH I.B. at 9. CPCNH states at page 11 that "FERC has recently examined these jurisdictional issues in two important Orders issued last year (after the LEEPA Study Commission) regarding interconnection requirements, and OATT amendments . . . ." The two orders cited were *ISO New England Inc*. (discussed above) and *PTOs*, but *PTOs* had nothing to do with interconnection jurisdiction.

[41] CPCNH I.B. at 12 & n.28 (emphasis added).

standard interconnection procedures and agreements that apply when an interconnection customer 'that plans to engage in a sale for resale in interstate commerce or to transmit electric energy in interstate commerce.'" seeks interconnection to a public utility's transmission or distribution system.[42] FERC was not making clear that all DER interconnections were state-jurisdictional in *ISO New England Inc.*; rather, it was making clear that it would accept an amendment to the ISO-NE Tariff that would treat certain interconnections *as if they* were state-jurisdictional because of the otherwise applicable confusing jurisdictional scheme that provided FERC jurisdiction over some DER interconnections. In short, the Filing Parties in that case were seeking an exception for DERs selling wholesale power that *were* subject to FERC interconnection jurisdiction; the Filing Parties did not allege that there were any DERs selling wholesale power in *intrastate* commerce.

That request was made because, at the time, in ISO-NE and elsewhere, jurisdiction over the interconnection of DERs selling at wholesale varied between FERC and state jurisdiction based on a multitude of factors, including: whether the DER is a QF[43] or is not a QF,[44] whether the distribution facilities the DER needs to use to deliver power had previously been used in interstate commerce,[45] whether the DER is in a DER

[42] *ISO New England Inc*., 180 FERC ¶ 61,129 at P 3 (citations omitted).

[43] *PJM Interconnection, L.L.C.,* 123 FERC ¶ 61,087 at P 5 (2008).

[44] *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003-C, 111 FERC ¶ 61,401 at P 53 (2005), *subsequent history omitted*.

[45] *Id.*

aggregation,[46] and to whom the DER intends to sell power if the DER is a QF (i.e., only the host utility[47] versus no limitation to the host utility[48]). The Filing Parties described how burdensome the resulting jurisdictional analysis is and FERC agreed that the ISO-NE proposal to exclude DERs from FERC's interconnection procedures was just and reasonable because it would promote certainty and reduce a significant burden on ISO-NE.[49] The rule applies only in the ISO-NE region.

FERC granted the relief requested in *ISO New England Inc.* to make *interconnection* jurisdictional determinations far easier. By espousing the notion that intrastate wholesale sales exist in New Hampshire, CPCNH and OCA are seeking to make wholesale sales jurisdiction incredibly more complicated. As noted earlier, a policy where wholesale sales that use *only* distribution facilities are intrastate and those where electrons may reach the transmission grid are interstate – can result in jurisdiction shifting from being in intrastate commerce to interstate commerce in the blink of eye, as loads and generation levels change every millisecond.

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[46] *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197 at P 47 (2021).

[47] 18 C.F.R. § 292.306 (2022).

[48] *E.g., Fla. Power & Light Co.,* 133 FERC ¶ 61,121 at PP 21, 23 (2010).

[49] *ISO New England Inc.*, 180 FERC ¶ 61,129 at P 20.

III. THE STATE CANNOT COMPEL WHOLESALE SALES OF TRANSMISSION (JOINT UTILITIES I.B. 14-17)

A. CPCNH mischaracterizes wholesale transmission sales as retail cost pass-throughs to claim the state would have jurisdiction.

In their Initial Brief, the Joint Utilities explained that RSA 362-A:2-b, XI(b) required the reassignment of transmission service from the distribution utility (as Network Customer) to LSEs, an action that the state could not compel. CPCNH addresses the issue of "[w]hether the statute or a regulatory order by the PUC 'can address how transmission charges assessed by the ISO[-NE] to network customers may or may not be allocated to load-serving entities . . . without being preempted."[50] CPCNH answers this question by claiming it is an issue of retail rate design.[51] CPCNH explains that the state has considerable authority over LSEs and the terms and conditions and rates they may charge retail customers.[52] The Joint Utilities agree that the states have authority over retail rate design, including mechanisms to recover the full transmission charge component of such retail rates. But the issue before the Commission in this proceeding is mandated wholesale transmission sales. In New Hampshire, other than the Commission-regulated distribution utilities and municipal utilities, LSEs do not buy transmission and then resell it at retail rates. More specifically, "retail electric service" (i.e., a combined

[50] CPCNH I.B. at 8.

[51] *Id.*

[52] *Id.*

set of delivery-related services) is sold by distribution utilities, such as the Joint Utilities.[53]

"'Electric utility' means a public utility as defined in RSA 362:2 that provides retail electric service."[54] And, electric utilities (i.e., distribution utilities) charge Commission-regulated rates for retail electric service. Electric utilities do not pass-through transmission costs to LSEs. As explained in their Initial Brief, if the Joint Utilities purchased transmission for *other* LSEs, i.e., entities who would resell the transmission at retail, then the Joint Utilities' sales to the LSEs would be FERC-jurisdictional transactions and cannot be mandated by the state.

CPCNH later states that a pilot sponsor could provide an option to allow:

> [S]uppliers (LSEs) to charge groups of retail customers for their actual share of transmission costs based on their share of coincident peak, including the load reducing effect of a limited producer in the ISO assessment of such charges, in what would essentially be a retail transmission cost pass through from the EDU through the retail supplier/LSE.[55]

If a distribution utility were to *voluntarily* take the total RNS charges allocated to it by ISO-NE and determine what portion of its total transmission charges should be allocated to each particular LSE, who would then sell retail transmission service, such action

[53] Retail electric service has been defined as "the delivery of electric power through the provision of transmission and/or distribution service by an electric utility to a retail customer, regardless of such retail customer's source of electric power, and shall include any back-up, maintenance, emergency, and other delivery service provided to a retail customer by an electric utility." *See* RSA 369-B:2, XII.

[54] *Id.* at IV.

[55] CPCNH I.B. at 9.

would be a wholesale transmission transaction subject to FERC jurisdiction. Aside from the federal preemption issue (i.e., that such sale could not be compelled by a state authority), this scheme imposes entirely new costs on both the distribution utilities and the LSEs and would render retail electric service billing administratively complex and potentially inefficient.

B. The cases cited by CPCNH do not support the position that transmission resales are subject to state regulation.

To defend its position on transmission resales, CPCNH points to how FERC transmission charges are "translated" into retail rates in Eversource's territory in Massachusetts, to Pennsylvania's approach to competitive suppliers buying transmission, and to PJM's Behind the Meter Generation program.[56]

CPCNH first describes how certain Massachusetts retail customers may choose to be billed for transmission based on their demand at the time of monthly coincident system peak load. The Massachusetts Department of Public Utilities ("Mass DPU") has indicated that Eversource should evaluate further the expansion of coincident peak transmission billing.[57] This discussion regards *retail* transmission rates charged by an Eversource-affiliated utility to *retail* customers and does not mention anything about reassigning transmission service to wholesale entities such as LSEs. The relevancy of this discussion of retail transmission rate design is not apparent.

[56] *Id.*

[57] *Id.* at 20-21.

As to Pennsylvania, according to CPCNH, transmission costs have "historically been paid for by competitive suppliers on behalf of the retail customers they serve, and paid for by the distribution utility only on behalf of the customers that remain on utility default supply."[58] CPCNH implies that this Pennsylvania approach is the norm in PJM by stating "in *PJM*, transmission costs are allocated to competitive suppliers for collection from customers.[59] Although Pennsylvania is "in PJM," CPCNH omits the fact that Pennsylvania is an *outlier* in allowing competitive suppliers to purchase transmission directly from PJM and/or to bill customers for transmission services. In most PJM states, if the competitive supplier can send a retail customer a bill *at all*, it is only for energy supply.[60] Interestingly, CPCNH quoted from Pennsylvania PUC Docket No. P-2020-3019522, a case where the vast majority of competitive suppliers *wanted* the utility to

[58] *Id*. at 21 & n.58 (citing Pennsylvania PUC, Docket No. P-2020-3019522, Order issued 1/14/2021, at p. 34. Online: https://www.puc.pa.gov/pcdocs/1690311.docx).

[59] *Id.* at 22 (emphasis added).

[60] *See* Ohio Admin. Code § 4901:1-21-14(B) (2023) (emphasis added) ("A CRES provider may bill customers directly *for competitive retail electric services* or arrange for the electric utility to bill customers for such services according to a tariff approved by the commission."). In New Jersey suppliers are allowed to send a bill only for electric supply, or can opt to rely on the utility to send a combined bill. *See* https://www.nj.gov/bpu/commercial/shopping.html#nbr4. In Maryland, "[r]etail energy suppliers sell directly to customers, using the local utility's distribution system to deliver electricity. Your local utility will still deliver your electricity and will send you a bill with the charges for both the delivery service and the energy supply." https://www.mdelectricchoice.com/how-it-works/. A Delaware government website notes that "[c]ustomers that choose to contract with a third party electric supplier will still receive a bill from their utility provider (Delaware Electric Cooperative or Delmarva Power)." https://depsc.delaware.gov/customer-electric-choice/. In Illinois, electric choice means that there is "a new price for electric supply on your bill." https://plugin.illinois.gov/electric-choice-basics.html. In Virginia, "[t]he utility will remain as your local distribution company (LDC), and a charge for delivery service will still appear on your bill. https://scc.virginia.gov/pages/Choosing-an-Energy-Supplier.

start buying transmission for all of its retail customers so the suppliers did not have to accept any transmission price risk.

The jurisdictional "problem" raised by the statute at issue here – compelling distribution utilities to procure wholesale transmission for LSEs – arises in states where competitive suppliers lack legal authority from the state to buy or bill for transmission directly. Under New Hampshire statutes, Community Power Aggregators ("CPAs")[61] and CEPS[62] are limited to selling "energy and capacity" and "electricity supply service" respectively. "Electricity suppliers" may provide "electricity generation services" and includes "electricity generators and brokers, aggregators, and pools that arrange for the supply of electricity generation to meet retail customer demand, which may be municipal or county entities."[63] Although not a *federal* preemption issue *per se*, CPCNH claiming in its Initial Brief that LSEs can simply start buying and billing for transmission service, on their own whim with no regard to existing law, reinforces the need to use the opportunity offered by *this preliminary process* to terminate this proceeding based on the

[61] RSA 53-E:4, I. "An aggregator operating under this chapter shall not be considered a public utility under RSA 362:2 and shall not be considered a municipal utility under RSA 38. A municipal or county aggregation may elect to participate in the ISO New England wholesale energy market as a load serving entity for the purpose of procuring or selling electrical energy or capacity on behalf of its participating retail electric customers, including itself."

[62] N.H. Code Admin. R. Puc 2002.08 (2022) (emphasis added) states "Competitive electric power supplier (CEPS) means any person or entity that sells or offers to sell all-requirements *electricity supply service* to retail customers, including net metering customers, in this state using the transmission or distribution facilities of a utility. A CEPS takes ownership of the electricity it sells. The term does not include any utility or any municipal or county corporation operating within its corporate limits or submetering at campgrounds as described in RSA 362:3-a." Emphasis added.

[63] RSA 374-F:2, II.

insurmountable jurisdictional issues. The legislation being addressed does not even recognize that all retail customers obtain transmission service from their distribution utilities, *under color of law*. Changing the law and implementing such a change likely would involve a complex and extensive undertaking by the New Hampshire Legislature and this Commission, with potentially great billing system modification costs.

Finally, CPCNH also points out that, under the PJM OATT, transmission load may be reported to electric distribution companies net of "Behind The Meter Generation." It explains that:

> utilities are relied upon to administer peak load calculations based on customer demand net of behind-the-meter generation – which, according to the definitions and service agreements in the *PJM OATT*, can include generation that delivers energy to retail loads <u>across</u> the distribution grid, and can even be counted as reducing the coincident demand of the competitive suppliers' entire customer base below zero (if properly metered and reported as-such).[64]

The claim that in PJM peak load calculations can be net of generation that delivers energy to retail loads across the distribution grid proves little else than that *another* RTO has allowed certain DERs to be used to reduce transmission load for cost allocation purposes. The PJM example does not in any way support the notion that FERC-jurisdictional public utilities procuring transmission service *for LSEs* is a state-jurisdictional activity; the PJM example does not even address the relevant issue.

[64] CPCNH I.B. at 21.

IV. ASSUMING AVOIDED TRANSMISSION CHARGES WERE FOUND TO EXIST, PREEMPTED COST TRAPPING (JOINT UITILITIES I.B. 17-20) CAN BE AVOIDED BY INCREASING RETAIL ELECTRIC SERVICE RATES

In their Initial Brief (at 17-20), the Joint Utilities expressed concerns that having to pay avoided transmission charges to an entity (yet to be clearly determined) could result in "cost trapping" in violation of the *Nantahala* doctrine. CPCNH brushes this concern aside by asserting that "[h]ow credit for [avoided transmission charges] might be realized through retail rates is a state jurisdictional matter . . . ."[65] In Section V of its Initial Brief, CPCNH expands on its position, noting that the Commission "cannot authorize the assessment of transmission charges in excess of those set by FERC" but that the Commission "has complete jurisdiction as to what those charges are called on retail bills and whether other state jurisdictional charges are included with the retail 'transmission charge.'"[66] CPCNH notes that "[t]here is no jurisdictional reason why the PUC could not approve use of the TCAM or a similar mechanism to account for payments to a limited producer for avoided transmission charges, as long as it ensures the ability of the utility to recover FERC authorized transmission charges as well."[67]

The Joint Utilities do not dispute that the Commission can add amounts of money to the TCAM and similar utility rate recovery mechanisms to ensure that payments to

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[65] CPCNH I.B. at 9. Although CPCNH and OCA both addressed why there would be avoided transmission charges, the Joint Utilities will refrain from addressing that substantive issue and assume its validity for purposes of this Reply Brief.

[66] CPCNH I.B. at 17.

[67] CPCNH continues on discussing *Hughes*, the relevance of which is rather unclear; but the discussion illustrates that state subsidies for generation can be lawful.

third parties based on avoided transmission charges are then collected from retail customers such that the relevant utility can recover its full ISO-NE mandated transmission costs.[68] The preemption/trapping issue could be "solved" through retail rate recovery of any such subsidy payment. However, absent such subsidy payment and recovery – that would of course raise retail electric service rates from what they otherwise would be – the problem remains.

In their Initial Brief, the Joint Utilities (at 17) expressed confusion about RSA 362-A:2-b, XI(c) which identifies three possible recipients of an avoided transmission charge payment – the LSE of the limited producer, the limited producer itself, or the LSE the limited producer sells to. CPCNH's Initial Brief discusses both an LSE being the recipient[69] and the limited producer being the recipient.[70] CPCNH does not appear to envision the payment going to the distribution utility, confirming that some type of retail rate subsidy would be necessary to make the distribution utility whole.

Whether the OCA would support the subsidy recovery approach as a "solution" to the potential preemption issue is unclear. OCA notes that "[c]onstruing RSA 362-A:2-b,

[68] This approach assumes there is a revenue gap, which would not be the case if the distribution utility is the LSE serving the limited producer and is the one paid based on the purportedly avoided transmission charges.

[69] CPCNH states that what happens with the avoided transmission charge as to an LSE is, "[i]n essence, as one part of the retail rate goes down (by the avoided costs from the ISO-NE market & transmission system) another part may go up, but by a little bit less than it would, but for the limited producer . . . ." CPCNH I.B. at 18 (citation omitted).

[70] CPCNH states that "[t]there is no jurisdictional reason why the PUC could not approve use of the TCAM or a similar mechanism to account for payments to a *limited producer* . . . ." *Id.* (emphasis added).

XI(a) in a way that accounts for the benefits of avoided transmission costs in the same manner that Unitil accounts for identical benefits from the Kingston Project would avoid an interpretation that results in federal preemption."[71] OCA's position is logical only if there is *no* payment for avoided transmission charges.[72] Under the Kingston Solar Project construct, Unitil benefits by reducing its Monthly RNL and that benefit accrues to all Unitil retail transmission customers, regardless of their LSE, because ISO-NE has imposed a smaller share of transmission charges on Unitil as a Network Customer.[73] Unitil will not be paying any avoided transmission charges to anyone, rather it is sharing the benefit of a lower wholesale transmission charge with all of its retail customers. RSA 362-A:2-b, XI(a), on the other hand, seems to require a payment to *someone* for the value of any avoided transmission charges. To make such a payment possible, the distribution utility *would have* to collect additional revenue from ratepayers to cover the cost of that remuneration or else costs would be trapped in contravention of federal law. Thus, the

[71] OCA I.B. at 6.

[72] Although not directly relevant to this particular argument, OCA's analogy is premised on a fundamental misunderstanding of the Kingston Solar Project. OCA asserts the "Kingston Project is . . . used in the . . . trading of electricity." OCA I.B. at 8. But Unitil's Kingston Solar Project will not be dispatched by ISO-NE, and it will not participate in ISO-NE markets (i.e., energy, capacity, etc.). Nor will the output be sold to another party through a bilateral contract. *But cf.* RSA 362-A:2-b, XIII (contemplating electricity purchases by LSEs as "intrastate wholesale transaction[s]").

[73] The Joint Utilities were perhaps imprecise in stating in an earlier pleading that the Monthly RNL of a Network Customer would be "reduced." The Joint Utilities agree that Monthly RNL could be reduced from what it would be, absent the exclusion of load served by unregistered generation resources. But, there are other factors that could impact whether avoided transmission charges actually exist and should be recognized. Consistent with the Commission's directive, that is an issue for another day.

Kingston Project and the proposed LEEP Act pilot programs are not comparable and this false analogy should be disregarded by the Commission.

In short, if the Commission were to find that avoided transmission charges had to be paid to a third party, the Commission also would need to require retail ratepayers to cover that subsidy payment in order to avoid a federal preemption issue.

V. THE ROLE OF ISO-NE UNDER THE TRANSMISSION OPERATING AGREEMENT ("TOA") MUST BE RESPECTED (JOINT UTILITIES I.B. 22-23)

With regard to the TOA and possible preemption claims, OCA states:

> [P]ilot programs whose activities are unrelated to the transmission of electricity located on, or making use of, the transmission facilities are excluded assets because pilot programs are taking place exclusively at the distribution level and do not participate in the ISO-NE wholesale market, even if owned by a transmission facility.[74]

Although this wording is somewhat difficult to parse, the primary point OCA appears to be making is that pilot program activities occur on the distribution system and involve "Excluded Assets,"[75] as that term is defined by the TOA. With regard to the TOA CPCNH states that:

> The TOA enables ISO-NE to be the transmission provider under the OATT and is not affected in any discernable way by any of the activities allowed by RSA 362-A and there is no basis to think of any of the activities allowed by RSA 362-A would cause a utility to violate such agreement.[76]

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[74] OCA I.B. at 8.

[75] OCA states at page 8 that "pilot programs . . . are excluded assets" which is illogical in that excluded assets as defined by the TOA belong to PTOs. Liberty is not a PTO, yet it may be expected to be asked to host a pilot program.

[76] CPCNH I.B. at 25.

The two transmission-owning Joint Utilities' preemption concern relating to the TOA revolves around the fact that the statute is so vague that the Joint Utilities simply cannot abide by both the statute and the ISO-NE Tariff, thereby violating their TOA obligations. One such problem is that the statute requires certain actions that the statute *assumes* are consistent with the current version of the ISO-NE Tariff, but the Tariff is mutable. For example, a primary goal of the LEEP Act appears to be that some entity, although it remains unclear who, can take advantage of ISO-NE's new approach to measuring transmission load as adopted in *PTOs*. A conflict could arise if, several years from now, as a result of *PTOs*, there is insufficient remaining load to reasonably bear the costs of the ISO-NE transmission system, and a decision is made to reverse the amendment approved in *PTOs*.

For example, assume that a limited producer invested in a resource with a 30- to 40-year life and is entitled to keep "avoided transmission charges." The limited producer expects there to be such payments, but within two years after project installation such payments cease because the ISO-NE OATT amendment excluding some load from RNL is reversed by ISO-NE or the PTOs through a FERC-filed amendment.[77] The statute should be clear that the limited producer has assumed the risk of a change to the ISO-NE Tariff eliminating a benefit, but it is not. Continuing to pay for avoided transmission charges in the event of a change in how RNL is measured would be preempted.

[77] It is possible that, after a few years of experience with the amendment approved in *PTOs*, it is evident that the Independent Market Monitor was correct that the amendment "could arbitrarily and discriminatorily shift transmission costs to Network Customers with no (or less) behind-the-meter generation." *PTOs*, 178 FERC ¶ 61,086 at P 22.

VI. CPCNH ACKNOWLEDGES THAT RECALCULATIONS UNDER THE ISO-NE OATT ARE NOT PERMITTED (JOINT UTILITIES I.B. 23-31)

CPCNH admits that the Commission cannot direct a market participant in the ISO-NE system to report its retail loads and/or the loads of other LSEs, "for purposes of energy, capacity, transmission, and any other FERC jurisdictional services, purchased at wholesale, from or through or otherwise assessed by the ISO[-NE], to serve retail load in a manner different than would otherwise be done under ISO[-NE] rules and procedures."[78] The Joint Utilities agree that any such requirement would create a preemption issue related to the state-mandated "recalculation" under the ISO-NE Tariff. And, in fact, such impermissible recalculations are effectively mandated by the statute, based on its terminology.

A. A proposed LEEP Act pilot program could not abide by both the ISO-NE Tariff and the state statute.

CNPNH states that, because pilots "must be proposed by an EDU, in conjunction with a CPA or a CEPS pursuant to RSA 362-A:2-b, VII, there is no reason to believe a pilot proposal would come forward that would cause such a reporting of loads for the purpose of any FERC jurisdictional services in violation of any ISO rules and procedures."[79] However, the critical issue is whether the Joint Utilities even *could* propose a pilot that *both* abides by the statute and does not impact load reporting to ISO-NE. One reason that crafting such a proposal would be rather difficult is that the requirements of the LEEP Act are unclear, given terminology such as the "load serving

[78] *See* CPCNH I.B. at 7 (citation omitted).

[79] *Id.* at 7.

entity serving the limited producer for load settlement in the ISO New England wholesale electricity market" and more generally, "their load serving entity," where "their" refers to limited producers.

This issue is perhaps most problematic with regard to RSA 362-A:2-b, X, which may be read to apply to the energy market. Although CPCNH's Initial Brief does not address this provision specifically, based on the fact that its brief discusses capacity load obligations, as if they were relevant to RSA 362-A:2-b, XIII, and transmission load obligations only in the context of RSA 362-A:2-b, XI, the Joint Utilities assume the topic of RSA 362-A:2-b, X may be the regional wholesale energy market. No party, however, resolves the problem identified in the Joint Utilities Initial Brief (at 26-28), namely that the LSE of a limited producer and the LSE(s) purchasing power from a limited producer may not be one and the same. This problem exists no matter what load obligation is being addressed by RSA 362-A:2-b, X.

A similar reason the Joint Utilities cannot conceive of a proposed pilot that would abide by both the state statute and the ISO-NE Tariff is that the statute refers to load serving entities rather than Market Participants in innumerable provisions, where Market Participant should be the correct term. The two entities are simply not one and the same. Abiding by both the statute and the ISO-NE Tariff would require a wholesale redrafting of either the tariff or the legislation. For example, RSA 362-A:2-b, X discusses accounting for an offset to a load obligation of an LSE for ISO-NE load settlement purposes. But no "LSE" has a load obligation for ISO-NE load settlement purposes. Only a Market Participant has a load obligation. Taken literally, no such offset could exist without changing either the statute to say "Market Participant for the LSE" or changing the ISO-NE Tariff to use the term "load-serving entity."

B. CPCNH and the Joint Utilities agree that capacity supply obligations cannot be recalculated.

The Joint Utilities and CPCNH seem to be in agreement that "capacity supply obligations to Generators registered with ISO-NE should not be impacted in any way,"[80] although how they reach that conclusion differs. The Joint Utilities explained in their Initial Brief that the statute made clear that the ISO-NE Tariff defined term "Capacity Supply Obligation" was being used, and that obligation relates only to resources participating in the ISO-NE forward capacity market and could not be changed by any state authority. CPCNH's discussion of the capacity obligation issue, in contrast, starts with a discussion of how capacity *load* obligations are to be allocated to meter domains and in turn to each individual Load Asset of each LSE.[81]

Presuming that CPCNH meant to refer to Paragraph XIII on pages 23 and 24 of its Initial Brief,[82] that statutory provision is impossible to parse in that LSEs, in their roles as LSEs, have no Capacity Supply Obligations to reduce. Resources (either directly or through their Lead Market Participants) have Capacity Supply Obligations. In effect, when CPCNH states that "[t]he overall capacity load obligation assigned to each LSE/market participant is inherently a FERC jurisdictional wholesale rate that can't be

[80] CPCNH I.B. at 8.

[81] CPCNH I.B. at 22-23.

[82] On page 25, CPCNH returns to citing the correct Paragraph of the statute.

second guessed or blocked from recovery by the PUC where it is part of EDU default service rates,"[83] it is effectively *admitting* that Paragraph XIII of RSA 362-A:2-b was *intended* to refer to a capacity load obligation. If CPCNH is correct as to the intended subject matter, then a legislative drafting error must have occurred.

Given that CPCNH's discussion at pages 22-25 seemingly relates to reducing capacity *load* obligations, that discussion is moot because the statute addresses capacity *supply* obligations. If Paragraph XIII were redrafted to clarify the reference, however, the question CPCNH raises – "whether it is within state authority for the PUC to require EDUs to assign to an LSE load asset a 'reduced capacity [load] obligation' resulting from a limited producer's export of power"[84] would be relevant and the answer to that question would be "no." The distribution utilities do not register Load Assets of other LSEs, they only provide information as Host Participants to ISO-NE with respect to individual customers' contributions to coincident peak load that are then used by ISO-NE to determine the capacity market payment obligations of LSEs with registered Load Assets. And the Joint Utilities as Host Participants cannot be directed by any state authority to reduce or otherwise change how those contributions or any related obligations are reported to or determined by ISO-NE. Only ISO-NE, a FERC-jurisdictional public utility under the FPA, is the entity with such authority, making the state statutory provision impossible to implement, even if it were properly re-worded and enacted. CPCNH

[83] CPCNH I.B. at 23.

[84] *Id.* at 24.

apparently agrees with that conclusion and suggests that pilot proposers could ask for accommodations from the NEPOOL Markets Committee and ISO-NE as a solution or somehow otherwise waive the provision.[85] As already discussed, there are simply too many problems with the entire proposed program to salvage any of it, as these solutions, even if they were possible, first require an amended statute and then further action by FERC-jurisdictional entities beyond the control of the Commission or any other state authority.

VII. THE DIFFERENCES BETWEEN CPCNH'S ILLUSTRATIVE PILOT PROGRAMS AND THE LEEP ACT SUPPORT A PREEMPTION FINDING

At the prehearing conference ("PHC"), Commissioner Chattopadhyay indicated his interest in examples comparable to the type and treatment of distributed generation contemplated by RSA 362-A:2-b. CPCNH provided two examples in its Initial Brief. Those examples merit some discussion because they demonstrate that convoluted approaches that attempt to, but ultimately cannot, avoid running into myriad jurisdictional (and other legal) issues are unnecessary. The examples provided, unlike the LEEP Act pilot programs under consideration here, actually work within the dual state-federal framework.

The first CPCNH example is the Vermont SPEED program, which is described by CPCNH as a feed-in tariff that was created pursuant to state law and a consensus

[85] *Id*. at 25.

settlement.[86] As already discussed, voluntary sales and purchases under the SPEED program are rate-regulation exempt PURPA sales. In this proceeding, CPCNH has been insisting on a program that does not involve *any* federal oversight or authority;[87] but SPEED is a program that relies on a federal law (PURPA) and on FERC's de-regulation of the rates of some power sales under PURPA regulations adopted by FERC.[88] SPEED is not a relevant example of a purely state-jurisdictional program. Were Vermont to *mandate* SPEED purchases, the Vermont Supreme Court has made quite clear that PURPA's avoided cost test would be applied.[89]

CPCNH next discusses the third-party battery ownership (2.5 MW) project implemented by the New Hampshire Electric Cooperative ("NHEC"), where NHEC can dispatch the battery to reduce coincident peaks, to reduce transmission charges and annual forward capacity market obligations for its system as a whole. Additionally, ISO-NE can dispatch the battery as an alternative technology regulation resource ("ATRR"). CPCNH states that "the battery owner buys the power output at wholesale (intrastate – and they didn't ask FERC permission) for resale to their retail customers and allows the

[86] CPCNH I.B. at 26-27.

[87] At the PHC, Mr. Below mentioned a Vermont program that was "purely under state-jurisdiction" and noted that "nobody has questioned whether FERC needs to intervene in those proceedings whatsoever." 5/16 PHC Tr. at 24:9-12. Presumably, he was referring to the Vermont SPEED program.

[88] The FPA rate exemption (18 C.F.R. § 292.601 (2022)) for 20 MW and smaller QFs is fully subject to FERC's control.

[89] *In Re Investigation to Review the Avoided Costs that Serve as Prices for the Standard-Offer Program in 2020*, 254 A.3d 178, 190-91 (Vt. 2021). In such case, an implementation claim against SPEED would be subject to federal jurisdiction.

owner of the battery to arbitrage hourly prices at other times."[90] A battery owner cannot buy its *own* power at wholesale, as the battery owner lacks retail customers. Presumably, CPCNH meant that the battery owner buys wholesale power to charge,[91] sells wholesale power to NHEC at some times, and at other times the battery is dispatched by ISO-NE as an ATRR.

In fact, the battery owner, as a wholesale power seller to NHEC, would be expected to obtain market-based rate authority from FERC because stand-alone batteries cannot be QFs (whose wholesale sales in interstate commerce are exempt from FERC rate regulation). In describing the example (as quoted on the prior page), however, CPCNH states that "they [i.e., the battery owner] didn't ask FERC permission." CPCNH presumably was unaware that the owner of the battery resource in question, ENGIE 2020 ProjectCo-NH1 LLC, did seek FERC permission to sell wholesale power in interstate commerce, although it was several months late in doing so.[92] On October 26, 2021, ENGIE 2020 ProjectCo-NH1 LLC filed at FERC a request to sell power from a 2,455 kWac lithium-ion battery energy storage system located in Moultonborough, New

[90] CPCNH I.B. at 26.

[91] The battery could *buy* energy to store at wholesale, *if* it resells such power at wholesale, under FERC Order No. 841. *Elec. Storage Participant in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 at P 4 (2018) ("[E]ach RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price (LMP)."), *subsequent history omitted*.

[92] If the Engie-affiliates company had owned a solar facility or a solar plus storage facility with the storage only charged from the solar facility, then it would have merely have had to file a QF self-certification with FERC.

Hampshire.[93] The battery owner subjected itself to FERC regulation as a public utility under the FPA so that it could make wholesale power sales in interstate commerce.

The NHEC battery program therefore is but one more example of how "FERC avoidance at all costs" is not a goal worth pursuing. And it may be worth noting that this example shows that DERs may be financeable in the free market, i.e., without state-mandated subsidies, and also without the creation of complex programs that ignore or even contravene FERC (and state) tariffs, laws, regulations, and policies, such as the pilot programs contemplated under the LEEP Act.

VIII. CONCLUSION

Wherefore, the Commission should find that there are jurisdictional conflicts between the LEEP Act and federal tariffs and policies that cannot be overcome. The Joint Utilities have demonstrated that arguments to the contrary lack merit or are not even relevant to the subject matter.

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[93] *See ENGIE 2020 ProjectCo-NH1 LLC*, Transmittal Letter, FERC Docket No. ER22-210 (filed Oct. 26, 2021).

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Respectfully submitted on behalf of the Joint Utilities,

Jennifer L. Key
Steptoe & Johnson LLP
1330 Connecticut Ave., NW
Washington, D.C. 20036
jkey@steptoe.com
202-429-6746

David K. Wiesner
Senior Counsel
780 N. Commercial Street
P.O. Box 330
Manchester, NH 03105-0330
David.Wiesner@eversource.com
603-634-2961

Counsel for Public Service Company of New Hampshire d/b/a Eversource Energy

Matthew C. Campbell
Senior Counsel
Unitil Service Corp.
6 Liberty Lane West
Hampton, NH 03842
campbellm@unitil.com
603-773-6543

Counsel for Unitil Energy Systems, Inc.

Michael Sheehan
Liberty Utilities (New Hampshire) |
Director, Legal Services
116 North Main Street
Concord, NH 03301
Michael.Sheehan@libertyutilities.com
603-724-2135 |

Counsel for Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

CERTIFICATE OF SERVICE

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

David K. Wiesner

Date: July 10, 2023 David K. Wiesner