Comments of the Community Power Coalition of New Hampshire (CPCNH) in response to the NECPUC Retail Demand Response and Load Flexibility Working Group's request for comments regarding retail program design considerations

September 6, 2024

Introduction

The Community Power Coalition of New Hampshire ("CPCNH")[1] appreciates the opportunity to provide these comments to the New England Conference of Public Utility Commissioners (NECPUC) Retail Demand Response & Load Flexibility Working Group in response to its request for comments regarding retail program design considerations. We look forward to engaging with the NECPUC Working Group throughout the upcoming workshop series.

CPCNH is a governmental instrumentality of its 63 members comprised of 61 New Hampshire municipalities and two counties and is organized pursuant to a Joint Powers Agreement (JPA) under New Hampshire state law.[2] CPCNH's mission is to foster resilient New Hampshire communities by empowering them to realize their energy goals. CPCNH is governed by an elected board of its members comprised of local officials, select board members, city councilors, and members of local energy committees. CPCNH creates value for its members by jointly contracting for energy supply services, developing projects and programs collaboratively, educating and engaging the public, and advocating for communities and customers at the legislature and state energy agencies. CPCNH's goals and values include: 1) delivering low and competitive rates to save customers money; 2) create more choices for customers through market competition and local control; and 3) support local economic development of energy projects and programs such as solar, energy storage, energy efficiency, weatherization, beneficial electrification/demand flexibility, and other innovative rate structures designed to optimize supply and demand.

CPCNH member communities comprise 35% of the state's population. In April 2023, CPCNH begun operation as a functioning joint power supply agency to procure and supply electricity and related services to member Community Power Aggregation (CPA) programs and is currently providing alternative default power supply service to 43 municipalities serving more than 140,000 customers as of June 2024. As of March 2024, CPCNH is the second largest power

[1] More information about the Community Power Coalition of New Hampshire can be found online at https://communitypowernh.gov.

[2] New Hampshire Revised Statute Annotated (RSA) 53-A and 53-E:3, II(b). In 2019, the Community Power Aggregation Act was signed by Governor Sununu which made certain changes to NH's existing CPA law; most notably, to empower communities to offer default (opt-out) energy service and other energy products through competitive markets to serve the interests of NH municipalities and counties.

supplier in New Hampshire by customer count. In October, CPCNH is preparing to launch an additional 14 CPA programs expected to serve ~170,000 customers in total. Since launching in 2023, CPCNH has been able to offer competitively lower rates than the three investor-owned utilities in NH.

Overview

The New England region and the independent system operator of the regional grid, ISO New England (ISO-NE) are entering a phase of rapid growth in renewable energy, accelerating energy storage deployments, and thermal generation retirements that represents a transformation in market fundamentals. Other regional wholesale markets that are further along in comparable transitions to high penetrations of variable renewable energy resources (e.g., ERCOT, CAISO, SPP) experience increasing energy price volatility, frequency of negative prices, renewable curtailments, and lower average energy costs offset by increasing capacity costs (and evolving capacity regimes).

In this context, demand flexibility will be increasingly important to supporting a reliable and least-cost energy system. Optimal price formation and economic efficiency occur when supply and demand can respond to the same price signals, which are highly temporal. With proper market platforms in place, grid-responsive buildings and community-scale Distributed Energy Resources (DERs) can provide demand flexibility that supports least-cost operations both locally and regionally.

In this context, "demand flexibility" means an increase or decrease in load and/or supply (whether generated or discharged) from devices interconnected below the Pool Transmission Facilities (PTF). DERs located behind a retail customer meter (e.g., dispatchable appliances, electric vehicles, solar, storage, etc.) and renewable energy generation and storage under 5 MW interconnected to the distribution grid can provide a pivotal role for flexible demand. ISO-NE tariffs and policies recognize such DERs, if not participating in ISO-NE markets, as "load reducers" relative to energy, ancillary services, capacity load obligations, and transmission charges. A "load reducer" reduces the energy or load that is measured at the boundary of the distribution system and the regional transmission grid. Generators connected to the distribution grid that sell their power into the federal jurisdictional wholesale markets also reduce the energy measured at the boundary of the transmission and distribution systems, but their generation is added back into the load calculation at that interface (known as "load reconstitution"). This is required since the generation is sold into the federal interstate wholesale market. On the other hand, a "load reducer" does not sell its energy into the interstate market, and instead acts as an offset or a reduction to the energy, capacity, and transmission charges that would otherwise be purchased through the ISO-NE absent the DER performance that can avoid such costs.

To date, retail energy programs administered by electric distribution utilities or companies (also known as EDUs or EDCs) and ratepayer funded investments in utility-owned DER projects have been crediting small-scale generation, energy storage, and demand response as "load reducers" for the purpose of achieving cost-effectiveness, counting, in particular, the value of avoided transmission costs. In contrast, CPCNH and other competitive suppliers and aggregators are unable to contract for or offer the most basic retail programs to their customers due to utility non-provision of Time of Use (TOU) and Net Metering data via Electronic Data Interchange (EDI); utility consolidated billing that only accepts a flat monthly volumetric rate; transmission costs based on share of coincident peak demand that are passed through to retail volumetrically with no temporal price signal; and wholesale load settlements and capacity obligations assessed by utilities that do not fully credit LSEs for their DER customers' exports to the distribution grid. These barriers appear to be widespread across New England and must be addressed in order for the competitive market (i.e., Community Power/Choice Aggregations or CPAs/CCAs and other competitive suppliers/third parties) to develop retail energy demand response and load flexibility programs as well as local energy projects for their customers on a competitive basis.

More broadly, ISO-NE's Director of Advanced Technology Solutions has identified the need to authorize "*local energy markets*" that are regulated by New England states and clarified that "*If DERs participate in the wholesale market directly, that's FERC jurisdiction. But if you want to set up a local energy market, that actually falls in the hands of the state*."[3] Similarly, PUC staff in California have recently identified the need to implement a "*statewide market platform for grid services*" — coupled with a "*centralized and standardized DER asset registry*" and "*equal access*" for "*non-IOU LSEs*" to real time grid data from utility AMI, ADMS, and DERMS platforms — to enable a "*distribution services market*" operating across multiple utility territories.[4]

Adopting such a "local energy market" framework for New England would animate DERs using price signals to convey the grid service needs of the bulk power, transmission, and distribution systems on an operational basis. This approach would enable more market innovation and widespread, equitable, and cost-effective deployment of demand flexibility — including by allowing CPAs/CCAs and other competitive suppliers to participate — while ensuring coordination and visibility with ISO-NE.

Implementation will require enabling changes to certain utility administered processes, as well as the creation of new market functions, many of which will benefit from regional coordination (and potentially standardized or joint deployments) which should be explored in NECPUC workshops.

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[3] *See* EPRI, Digital Grid Virtual Workshop - Integrating Customer Resources, Presentation "09-Digital Grid - The Value of Resilience for Customer DERs Panel (August 5, 2020)" at 1:18:15. Available online under "Attachments" > "Media" at: https://www.epri.com/research/sectors/technology/events/6182D0F6-9731-4819-83FD-3A126EEEF61.3

[4] *See* CPUC R.22-11-013, Data Working Group Kickoff (August 26, 2024), pp. 17-18 at: https://ucla.app.box.com/s/95zwll4bl9e6arxkmfgxs3o5ntkwn73s.

Data Sharing

The current state of data interchange between utilities, non-utility LSEs, and DER aggregators is fragmented and very inefficient. For example, Electronic Data Interchange (EDI) in NH usually omits net metered customer energy exports and TOU usage data, and the only deployment of Green Button functionality to date in New England — where advanced metering infrastructure (AMI) has been deployed in Maine — is noncompliant with the Green Button standard and has "severe errors."[5]

When you consider how enabling innovative third-party services will require expanded access across multiple utility systems, and also how data from third parties will need to start flowing back to inform market operations, it becomes apparent that states simply need a better approach to enabling data exchange that is standardized, efficient, and extensible.

This need has given rise to the New England Regional Data Hub proposal, developed initially in New Hampshire and subsequently joined by utilities and stakeholders operating in Massachusetts and Connecticut (along with Unitil's gas affiliate in Maine), which was recently submitted to the US Department of Energy as a GRIP Grant Proposal. The concept would establish a centralized portal for customers and authorized third parties to obtain and stream energy data from participating utilities using modern APIs (application programming interfaces) and standardized authorization, protocols, and data formats for third party access to individual and aggregated customer energy data. The first phase would require utilities to certify their Green Button implementations, and utilities would ultimately be responsible for transmitting data from their meter data, billing, and customer information systems upon request (or streamed) through the data hub. The platform is planned to be extensible over time to potentially incorporate additional data sources and sharing, such as from Distributed Energy Resource Management Systems (DERMS) and DER owners and operators. A neutral third-party vendor would maintain the central data access portal and would manage third-party registrations and permissions. Updates to the data model and formats would be overseen by a representative council of industry and public stakeholders.

Currently most of NH's investor-owned utilities are not able to provide CPCNH (and presumably, other suppliers and third-party aggregators) with data on exported generation from net-metered systems through their EDI systems. Periods during which customer-generators are exporting electricity to the grid show up in most of the data as zero consumption, rather than as negative consumption (or as positive generation). Without knowing how much electricity net-metered systems are exporting to the grid, CPAs/CCAs and competitive suppliers cannot properly compensate net metered customers for their exports. As such, the competitive market in NH is effectively unable to serve net metering customers — despite demand for such programs along with state energy policy, which calls for such retail energy services to be provided to customers on a competitive basis. Though this comment is framed in terms of net metering, this

[5] *See* Mission:Data, Green Button Explorer (accessed 8/30/24), at: https://explorer.missiondata.io/.

same data issue potentially applies equally to other DERs with export capabilities, such as batteries and bi-directional EV chargers. Work in the New England states' Electronic Business Transaction (EBT) / Electronic Data Interchange (EDI) working groups can address this issue which would benefit from increased regulatory oversight and direction. There are solutions to address these issues; however, the bottleneck is implementation by stakeholders.

The NECPUC workshops should discuss the benefits of expanding data access in a standardized fashion across New England and encourage additional states, utilities, and other stakeholders to participate in the New England Regional Data Hub initiative.

Wholesale Load Settlements

In the restructured New England states, EDUs/EDCs are responsible for administering the wholesale load settlement process that determines how much electricity each supplier purchases from the ISO-NE markets. Current utility practice does not credit individual suppliers for demand response and improvements to load shape from flexible load for customers without interval metering, as well as for the electricity exported to the distribution grid from DERs who net meter.

The load settlement process involves utilities reporting wholesale supply for LSEs within the EDUs/EDCs' service area based on assumed customer-class load profiles and capacity tags scaled to their usage, (with the exception of large C&I customers who have interval metering where their interval data can be used for load settlement and allocation of account-specific capacity tags). Otherwise, unaccounted for deviations from class average load shapes, which are based on a limited number of research meters, including from demand response and exports to the grid from distributed generation and storage, are aggregated in what is called the "residual" and then socialized across all suppliers operating in a utility's service territory, in proportion to the percentage of load that each supplier serves. This means that actual hourly (temporal) usage by customers is ignored, so any price signal from an innovative rate is also ignored. As an example, currently most net metered customers are assumed to have standard residential or commercial class average load shapes, completely ignoring their solar PV production or even exports during the day. Instead, the energy use (if any) over the day or month is spread out across all hours of the day or month, consistent with the class average load shape being applied to the account. This simplified process results in suppliers being assigned and charged for load by ISO-NE that is not actually supplied by ISO-NE because the load is offset/supplied locally, This socialization removes any benefits from a price signal that would otherwise incentivize a customer to use energy during less-costly periods or even export energy during high-cost periods.

The current load settlement practices are causing far-reaching structural impacts that are also obstructing optimal investment. To illustrate this as an example, let us assume that Supplier A planned to implement a battery storage program that encourages participating customers with batteries to charge during low-priced periods and discharge during high-priced and peak periods. Such a program could result in significant grid system savings by reducing load at key times of high demand and thereby avoid the need for Supplier A to purchase expensive energy, capacity, transmission, and ancillary services at coincident peak hours at the steepest part of the marginal price curve. However, under current load settlement practices, Supplier A would only be able to capture a fraction of those savings, equivalent to the fraction of load that it serves within the given utility service territory (e.g., ~10%). The remaining ~90% of those savings that are directly attributable to Supplier A's battery storage program would be distributed across all other suppliers operating in the utility service territory in proportion to the percentage of load served. The fact that Supplier A can only capture a fraction (e.g., 10%) of the program's value in turn affects the amount that it can pay to compensate the behind-the-meter (BTM) batteries for the benefits that they provide. In other words, Supplier A can only pass through to the BTM batteries the value that it actually receives — which is far less than (e.g., only 10% of) the value that those batteries have provided to the grid system. This quickly becomes a "chicken or the egg" situation — i.e., because Supplier A cannot fully compensate batteries (or other DERs such as solar PV systems, or controlled water heaters, or bi-directional EV chargers) for the value that they provide. As a result, those batteries and other devices are less likely to participate (or even be deployed) in the first place. Too often, the end result is that the program is not offered, and the benefits of the load-shifting do not occur, leading to inefficient investment in the expansion of the distribution and/or transmission and bulk generation systems and significant lost savings to ratepayers.

As competitive suppliers and CPAs/CCAs serve more load across the region, the lost opportunity to offer competitive innovative rates and programs grows. This, in turn, results in the loss of leveraging private investment (including from consumers) in DERs and beneficial electrification technologies that can take advantage of cost savings from innovative rates. This lost private investment results in 30- to 50-year public investment in distribution and transmission systems that try to solve for peak capacities that could have been reduced through private investment in price responsive DERs, beneficial electrification technologies, and other grid technologies.

This should be addressed by reforming load settlement practices as soon as possible. Some New England EDUs/EDCs may be able to do this quicker than others, and this should be prioritized so that customers may start to access competitive innovative rates. One option that the NECPUC workshops could explore is the cost and benefits of using a third-party single load settlement provider (like VT does, with VELCO) rather than requiring each EDU/EDC to make the changes independently. For instance, in New Hampshire, three of the four EDUs/EDCs contract out with the same third-party vendor to perform load settlements, so there may be a cost-effective advantage to working with a single vendor, particularly with similar load settlement reforms in the works to enable aggregated DERs to participate in the ISO-NE market pursuant to FERC Order No. 2222 and subsequent implementing orders. On the other hand, one utility invested in its own customized load settlement system for all of its New England affiliates.

In terms of priority, reform to load settlement is the most critical to enabling customer and community choice through a competitive market for cost-effective demand response and load flexibility programs as well as other DERs. To underscore this point, even if the data sharing and utility billing barriers described herein were removed, CPAs/CCAs and other competitive suppliers still could not create effective retail programs under current load settlement practices. However, the reverse is not true; if only load settlement was reformed, as there are workarounds for the data and billing issues, the competitive market would be able to offer innovative rates and retail programs supporting demand response and flexible load. CPCNH recommends that this issue be explored in the NECPUC workshops.

Capacity Load Obligations

As AMI is increasingly deployed across New England, customer-specific capacity tags can and should be used in load settlement. This has been largely done for larger C&I customers where a fairly robust demand response market has developed to help curtail their load and capacity tags for the following power year for those customers with flexible loads. In addition, there should be a means by which each supplier's capacity load obligation (CLO) can reflect not just consumption loads at the hour of annual system peak, but also total load net of exports to the grid by their customers up to, but not exceeding, the total of their customers' consumption or positive capacity tags. This is another topic worth exploring in the workshops.

Transmission Cost Allocation

Transmission costs in New England are allocated to EDUs/EDCs based on share of monthly hour of coincident peak demand, which in turn mostly reallocate such costs on a kWh basis that are apportioned to each rate class based on class average load shapes. In ordering the expansion of opt-in, customer-specific charges for transmission costs for large C&I customers in Eversource's territory based on their actual share of coincident peak demand, the Massachusetts DPU found that "this allocation method sends a more accurate price signal to customers regarding the true cost of transmission service and is consistent with how FERC designs transmission rates, under which NSTAR Electric receives transmission service"[6] and that "pricing transmission service based on a customer's consumption at the time of system peak rather than based on the customer's peak, which may not coincide with the system peak, provides a more equitable assignment of cost responsibility."[7]

The NH Value of Distributed Energy Resources study recently conducted for the NH Department of Energy[8] and PUC found that much of the potential value of DERs going forward is in avoiding and reducing transmission charges by reducing monthly coincident peak demand.

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[6] Massachusetts Department of Public Utilities, Docket No. 17-05, Order No. D.P.U. 17-05-B (January 5, 2018), at p. 211. Online: https://www.mass.gov/files/documents/2018/01/26/17-05-B_Order_1-5-18.pdf.
[7] *Ibid*., at p. 212.
[8] https://www.energy.nh.gov/value-distributed-energy-resources-study.

Because of the year-round nature of this very strong temporal price signal, translating it into a retail price signal that retail loads and DERs can respond to would incentivize winter peak load reduction.

One way to strongly encourage suppliers and, consequently, individual retail customers to manage demand and DERs to reduce coincident peak demands is to allocate transmission costs to suppliers based on their share of such coincident peak demands, as is done in Pennsylvania in PJM where transmission charges are referred to as "Network Integration Transmission Service" ("NITS") and are paid for by each "Network Customer," which are defined as entities that are either "participating in a state required retail access program and/or a program providing for the contractual provision of default service or provider of last resort service."[9]

In Pennsylvania, consequently, where unbundling of transmission rates was required pursuant to the state's Customer Choice and Competition Act, 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.[10]

PJM's OATT, Specifications for Network Integration Transmission Service Pursuant to State Required Retail Access Programs, requires that (emphasis added):

> *For Network Load within the PJM Region, the Network Customer shall arrange for each electric distribution company ("EDC") delivering to the Network Customer's load to provide directly to the Transmission Provider, on a daily basis,* ***the <u>Network Customer's peak load</u> (net of operating Behind The Meter Generation, but not to be less than zero, unless such generation is separately metered and reported to PJM)****, by bus, coincident with the annual peak load of the Zone as determined under Section 34.1 of the Tariff… The information must be submitted directly to the Transmission Provider by the EDC, unless the Transmission Provider approves in advance another arrangement…* ***For Behind The Meter Generation of a Network Customer that requires metering pursuant to section 14.5 of the Operating Agreement, the Network Customer shall arrange for the Transmission Owner or EDC to provide directly to Transmission Provider information pertaining to such Behind The Meter Generation and the total load at its location as necessary for PJM's planning purposes****."*[11]

Further, PJM's OATT provides that generation units that deliver energy to load across distribution facilities may qualify as "Behind the Meter Generation" (emphasis added):

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[9] PJM OATT, Attachment F-1, Form of Umbrella Service Agreement for Network Integration Transmission Service Under State Required Retail Access Programs, p. 1. Online, beginning at p. 2093: https://pjm.com/directory/merged-tariffs/oatt.pdf.

[10] *See* Pennsylvania PUC, Docket No. P-2020-3019522, Order issued 1/14/2021, at p. 34. Online: https://www.puc.pa.gov/pcdocs/1690311.docx.

[11] PJM OATT, Attachment F-1, Form of Umbrella Service Agreement for Network Integration Transmission Service Under State Required Retail Access Programs, pp. 3-4. Online, at pp. 2095-2096: https://pjm.com/directory/merged-tariffs/oatt.pdf.

> *"Behind The Meter Generation refers to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (**unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities** and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market."*[12]

Thus, in PJM, transmission costs are allocated to competitive suppliers for collection from customers, and utilities are relied upon to administer peak load calculations based on customer demand net of BTM generation — which, according to the definitions and service agreements in the PJM OATT, can include generation that delivers energy to retail loads across 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).

Such an approach merits consideration in the five New England states with customer choice and competitive supply of electricity.

Consolidated Billing

Under the current "Rate Ready" billing regime in which most CPAs/CCAs and competitive suppliers that operate in New Hampshire, Massachusetts, and perhaps the rest of New England, are currently unable to offer supply rates for any time interval shorter than monthly (while remaining on the EDU/EDC's consolidated bill). The promise of electric utility restructuring to provide competition in power supply requires a level playing field so customers can have meaningful choices. TOU and net metering rates should be treated no differently than monthly default service rates. Utility billing systems are continually being invested in (with costs recovered in rates) to stay updated and modernized. This feature should be a requirement to unlock the benefits of competition and give customers choice in not only generation supply, but also demand response services and rate structures. This technical billing issue poses a barrier to the competitive market being able to offer innovative rates.

"Bill Ready" billing — whereby the competitive supplier calculates the amount owed and passes that amount (rather than just the rate) to the utility for inclusion on their bill—is a possibility; but the cost to implement maybe high/prohibitive to do for a single jurisdiction. Dual billing, whereby the utility bills only for T&D services and the supplier bills separately for supply services is another possible solution. Dual Billing would solve some problems (e.g., suppliers

[12] PJM OATT, Common Services Provisions, OATT 1. Definitions, p. 8. Online, at p. 41: https://pjm.com/directory/merged-tariffs/oatt.pdf.

could structure and bill for supply rates however they want—*subject to surmounting the other barriers discussed in these comments*) but would raise other considerations (customer preference for a single bill, cost, collection of receivables, etc.).

Perhaps the most readily implemented and least-cost option would be for utilities to update their EDI/EBT (electronic data interchange and electronic business transactions) to enable competitive suppliers to offer TOU rates (corresponding to utility TOU time periods, whether 3-part or 2-part periods) and on-bill credits (for exports to the grid) in "Rate Ready" consolidated billing.

DER Retail Market Platform

The changes described above would serve to promulgate grid-responsive DERs broadly, outside of utility administered programs, and would be expected to significantly accelerate the deployment of DERs and cost-effective integration of variable renewables at the bulk power and transmission system level. To additionally enable EDUs/EDCs to contract for flexibility in order to meet local distribution system requirements, other markets have deployed DER market platforms operated by neutral third parties that facilitate contracts for grid services in a transparent and standardized fashion and coordinate DER dispatch with regional wholesale markets. These deployments are widespread in the EU. Piclo Flex is one leading provider with over 60,000 assets / 19 GW of demand flexibility in the EU and has recently deployed flexibility market platforms in New York and in Connecticut.[13]

The NECPUC workshops should discuss the benefits of coordinating similar deployments of demand flex market platforms across New England, particularly by enabling the competitive market to leverage these suggested market reforms to incentivize optimal private investment that benefits all ratepayers.

[13] See PicloFlex press release (7/7/24), at: https://www.piclo.energy/press-releases/eversource-and-united-illuminating-launch-new-englands-first-grid-flexibility-marketplace-for-winter-2024-25-with-piclo.