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Clarifications on LMS Compliance Plans

Additional submitted attachment is included below.

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November 3, 2023

California Energy Commission
715 P Street
Sacramento, CA 95814
ATTN: Executive Director Drew Bohan

RE: Clarifications on LMS Compliance Plans (Docket No. 23-LMS-01)

Dear Mr. Bohan:

On behalf of the Utility Consumers' Action Network (UCAN), I am submitting these comments to help align and coordinate your review of 2023 Load Management Standards (LMS) Compliance Plans with the ongoing California Public Utilities Commission (CPUC) Demand Flexibility Order Instituting Rulemaking (DFOIR) proceeding (R.22-07-005).

UCAN is a 501(c)(3) non-profit public benefit corporation dedicated to protecting and representing the interests of residential and small business customers in the San Diego Gas & Electric service territory. UCAN has a forty-year history of intervening in CPUC proceedings on behalf of SDG&E customers and is an active participant in the DFOIR proceeding.

Pacific Gas and Electric's (PG&E) LMS Compliance Plan represents that *"…PG&E's benchmarking was unable to identify any active RTP rates in the United States that include a dynamic transmission element*" while acknowledging in a footnote that *"In comments on the Joint IOU WG 1 Proposal, Utility Consumers' Action Network mentions that New Hampshire has an hourly rate that "passes through time-differentiated transmission rates (typically, in 3 to 6 price spikes that occur at different times each month)." PG&E was unable to locate any details regarding this transmission rate."*[1]

UCAN would like to clarify that PG&E was referring to the New Hampshire Electric Coop (NHEC) Transactive Energy Rate (TER) Pilot Program,[2] which UCAN included in our informal comments on the DFOIR Working Group 1: Joint IOU Proposal and in subsequent comments regarding DFOIR pilot proposals.[3] Our comments on the DFOIR Working Group 1: Joint IOU Proposal also provided citations and directed the Joint IOUs to UCAN's prior comments in the High DER Future proceeding for further information regarding NHEC's TER Pilot Program. [4] In turn, our comments in the High DER Future proceeding provided citations and directed interested parties to comments filed by the

[1] PG&E 2023 LMS Compliance Plan, p. 8 and fn. 25.
[2] NHEC, TER Pilot Program. Online: https://www.nhec.com/energy-management/transactive-energy-rate-program
[3] Demand Flexibility Proceeding (R.22-07-005), UCAN Comments on the August 15, 2023 Administrative Law Judge's Ruling on Track B Proposal to Expand Existing Pilot, 25 September 2023, Attachment A, pp. 6 to 13. Online: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K482/520482485.PDF
[4] High DER Future Proceeding (R.21-06-017), Comments of the Utility Consumers' Action Network (UCAN) on Administrative Law Judges' May 9, 2023 Ruling Setting a Workshop, Admitting into the Record Part 1 of the Electrification Impacts Study and Research Plan, and Seeking Comments, 28 July 2023, pp. 7 to 8. Online: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M515/K973/515973863.PDF

Community Power Coalition of New Hampshire for even more detail regarding NHEC's TER Pilot Program.[5]

Given the extent of the record described above, UCAN is unsure why PG&E's LMS Compliance Plan represented that the utility had been "*unable to locate any details*" regarding NHEC's transactive energy rate. For ease of reference, UCAN has appended the three aforementioned sets of comments here. UCAN is also unsure why the other examples of dynamic transmission pricing implementations provided in our comments to the Joint IOUs were not mentioned by any of the IOUs in their respective LMS Compliance Plans. UCAN brought this subject up at a DFOIR workshop hosted by Energy Division staff on October 17, 2023,[6] and anticipates submitting formal comments addressing the matter in R.22-07-005.

Similarly, UCAN is concerned that PG&E's LMS Compliance Plan assumes that the utility will propose LMS-compliant transmission rates to FERC, and subsequently to the CPUC for approval, whereas Southern California Edison's (SCE) LMS Compliance Plan assumes the opposite, i.e., that the utility will propose LMS-compliant transmission rates first to the CPUC and subsequently to FERC. UCAN questioned the utilities at the DFOIR Workshop regarding why divergent processes were being proposed,[7] and has urged the CPUC to exercise additional oversight over this key issue in R.22-07-005 as well.

Finally, UCAN has raised concerns regarding SCE's request for an exemption to implementing LMS-compliant rates until "*2032 or 2033*", which the utility believes is warranted because "*final guidance*" from the CPUC regarding real-time pricing rate design "*might not be received until the second quarter of 2028*" given the 3-year real-time pricing pilot timeline extension under consideration in R.22-07-005.[8] Energy Division staff and UCAN questioned SCE regarding their contention at the DFOIR Workshop[9] and UCAN subsequently urged the CPUC to clarify that any pilot extension should not be used as an excuse by SCE to delay implementation of LMS-compliant RTP rates past 2027.[10]

Respectfully submitted,
/s/ Jane Krikorian

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Attachments:

1. UCAN informal comments submitted 25 August 2023 in R.22-07-005
2. UCAN comments filed 28 July 2023 in R.21-06-017
3. Community Power Coalition of New Hampshire comments filed 13 June 2023 in NHPUC IR 22-076

[5] NHPUC, IR 22-076, Community Power Coalition of New Hampshire Final Comments, 13 June 2023. Online: https://www.puc.nh.gov/regulatory/Docketbk/2022/22-076/LETTERS-MEMOS-TARIFFS/22-076_2023-06-13_CPCNH_FINAL-COMMENTS.PDF

[6] R.22-07-005, DFOIR Workshop (Part 3 Recording), 17 October 2023, discussion at 1:46:17 to 1:54:37. Direct link: https://files.cpuc.ca.gov/energy/DemandFlexibilityMgmt/Demand Flexibility OIR (R.22-07-005) Workshop on Track B Working Group Proposals-20231017_Part3.mp4

[7] *Ibid.*, at 1:36:54 to 1:42:29.

[8] SCE 2023 LMS Compliance Plan, p. 5.

[9] DFOIR Workshop (Part 2 Recording), October 17, 2023, discussion at 2:07:51 through 2:17:20. Direct link: https://files.cpuc.ca.gov/energy/DemandFlexibilityMgmt/Demand Flexibility OIR (R.22-07-005) Workshop on Track B Working Group Proposals-20231017_Part3.mp4

[10] R.22-07-005, UCAN Final Comments on the August 15, 2023 Administrative Law Judge's Ruling on Track B Proposal to Expand Existing Pilot, 25 October 2023, p. 8. Online: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K649/520649765.PDF

ATTACHMENT 1

R.22-07-005, UCAN informal comments on Demand Flexibility Order Implementing Rulemaking (DFOIR) Working Group 1: Joint IOU Proposal, submitted 25 August 2023

Required Elements	Description
Organization(s)	Utility Consumers’ Action Network (UCAN)
Proposal Name	Joint IOU Proposal for Load Flexibility Rates
For each box below, input your comments that address the specific scoping question and should include, at a minimum, areas of support and/or opposition to the proposal (or portions of proposal) including justification and any recommend changes	
Question 3	
Question 3a	
Question 3b	
Question 3c	
Question 3d	
Question 3e	
Question 3f	**<u>RE: TRANSMISSION, FERC & RETAIL RATES</u>** The Joint Utilities assert that FERC must approve a <u>specific</u> methodology for retail rates to recover transmission costs. As select examples: • Page 13: “TOU transmission retail rates must be submitted for FERC approval prior to including a time-differentiated transmission price signal in any of the IOUs’ retail rate plans in support of load management goals in California.” • Page 16: “Dynamic transmission (which would first require FERC approval) and circuit-specific distribution prices.” • Page 18: “None of these pilots includes a dynamic transmission element because there is not yet clarity on how the transmission element should be designed (i.e., which transmission costs should be included and how), and how procedurally a dynamic transmission proposal could be adopted by FERC. [Footnote 43: None of the Joint IOUs’ pilots have been designed with a dynamic Transmission component pending determination of regulatory approval process at the Federal Energy Regulatory Commission (FERC), given that the CEC and CPUC are unable to adopt transmission component rate designs without FERC approving that rate design.]” • Page 28: “Transmission marginal costs are not currently used to design transmission retail rates and TOU transmission retail rates have not yet been presented at FERC by the IOUs. As noted, FERC approval would be required to implement dynamic transmission pricing, given FERC’s exclusive jurisdiction over transmission rates. Each IOU is at a different stage of exploring TOU-differentiated transmission retail rates. None of the IOUs have begun looking at dynamic hourly transmission pricing:…”

	Based on this assumption, the Joint Utilities propose that additional studies will need to be conducted, to determine appropriate methodologies for retail rates, after which FERC would be asked to approve new retail rates. The timeline and process for this is unclear, and the outcome is uncertain, which renders compliance with LMS requirements ultimately "subject to FERC approval" (p. 20). **The Joint Utilities proposal should be modified to reflect the fact that FERC does not need to approve specific methodologies for retail rates, or specific retail rates, for the recovery of transmission costs from retail customers.** **The Joint Utilities should instead propose to expedite a single-issue filing at FERC to address the need for the CPUC and CEC to exercise discretion regarding how transmission revenue requirements — which would continue to be set and allocated in accordance with formula rates overseen by FERC — are ultimately recovered from retail customers in California.** FERC permits other states comparable discretion regarding how transmission costs are charged to retail customers, and there are numerous examples from around the country that are highly relevant and instructive for the purposes of this proceeding. This was the subject of an explicit discussion at the July 21, 2023, working group meeting. Energy Division staff asked the Joint Utilities (1) whether "any part of the country" had "any kind of time differentiated transmission rates" and (2) whether any utilities pass through transmission costs to retail customers based on the customer's share of demand on a monthly coincident peak basis ("12CP").[1] At the time, the Joint Utilities could not offer an informed opinion, but committed to further researching those questions. Relevant here is that the answer to both questions is "yes". As explained in more detail below: • In Massachusetts (in ISONE), there are customers being charged for transmission based on their individual share of monthly coincident peak demand. • In New Hampshire (also in ISONE), there is an hourly real-time pricing program that passes through time-differentiated transmission rates (typically, in 3 to 6 price spikes that occur at different times each month). • In Pennsylvania (in PJM), both utilities and competitive suppliers are allocated transmission costs for recovery from their respective customers, and how competitive suppliers charge customers for

[1] Track B, Working Group 1, July 21, 2023, at minute 51:00 and 52:23 of the recording.

	transmission is not regulated (i.e., there is no prescriptive or set retail rate for transmission). Furthermore, transmission is allocated based upon coincident demand net of behind the meter generation (and in front of the meter generation is also allowed to be netted out as well). **For all of these states, FERC oversees and approves the ratemaking process that determines the formula rates used to set transmission revenue requirements and allocate costs — but the *retail rate* that is ultimately relied upon to recover and pay for those costs is determined by entities other than FERC (e.g., state regulatory commissions, distribution companies, and/or competitive suppliers).** Clearly, FERC allows significant latitude to states to determine how transmission costs should be recovered in retail rates. Additionally, as particularly relevant to the Joint Utilities proposal: • Massachusetts regulators recently ordered that more customers should be allowed to opt-in to paying for transmission based on their individual coincident peak demand — without first seeking permission from FERC to do so. • The real-time pricing program deployed in New Hampshire, passing through time-varying transmission price signals to customers, did not require FERC's approval prior to implementation. • Pennsylvania regulators recently debated whether transmission costs should be recovered by utilities through nonbypassable charges, instead of continuing the practice of having competitive suppliers recover the costs freely from customers — and at no point did the Commission anticipate needing to seek FERC's permission prior to making the change. (The Commission decided that competitive suppliers should continue to charge transmission costs to customers). The Joint Utilities proposal is significantly weakened by the assumption that FERC's approval will be necessary to authorize any changes to retail rates for transmission. Amending the proposal to expedite a single-issue filing at FERC allowing the CPUC and CEC to exercise discretion regarding how transmission revenue requirements are charged to retail customers would (1) better align with achieving LMS requirements, (2) increase the ability of the Joint Utilities to meet the implementation schedule mandated by the CEC, and (3) permit more flexibility to evolve retail rates on an ongoing basis. More detailed summaries of each state are provided below:

Massachusetts

Eversource (an investor-owned utility) was ordered by the Massachusetts Department of Public Utilities ("MA DPU") to charge their Extra Large T-5 customers for transmission based on their individual metered demand at the time of the monthly transmission system peak. The rate was implemented in accordance with an order issued in 1997. Below is the relevant tariff language:

> *"Pursuant to D.P.U. 12-97, Rate T-5 customers will be billed on the customer's demand at the time of the ISO New England regional network monthly transmission system peak (the Coincident Peak Demand) for the legacy Northeast Utilities system… The Coincident Peak Demand shall be determined by meter, each calendar month on a one-month lag basis and shall be the customer's coincident 60-minute kilowatt demand."*[2]

Coincident peak transmission billing was subsequently expanded in a 2018 decision in which the MA DPU found that (emphasis added) "**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 [d.b.a. Eversource] receives transmission service"[3] 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."[4] Consequently, the MA DPU directed Eversource "to evaluate further the expansion of coincident peak transmission billing to NSTAR Electric customers.[5]

Consequently, Eversource extended coincident peak transmission billing on an opt-in basis to their Large General Service Rate G-3 customers across the utility's Western Massachusetts territory[6] and Eastern Massachusetts territory — the latter comprised of the Cambridge Service Area,[7] Greater Boston

[2] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 43E, Western Massachusetts Extra Large General Service Rate T-5, at pp. 2-3. Online: https://www.eversource.com/content/docs/default-source/ratestariffs/ma-electric/43-tariff-ma.pdf?sfvrsn=367cbc2b_3

[3] 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

[4] *Ibid.*, at p. 212.

[5] *Ibid.*, at p. 213.

[6] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 42F, Western Massachusetts Extra Large General Service Rate G-3, at pp. 2-3. Online: https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/21-tariff-ma.pdf?sfvrsn=e57e110f_3

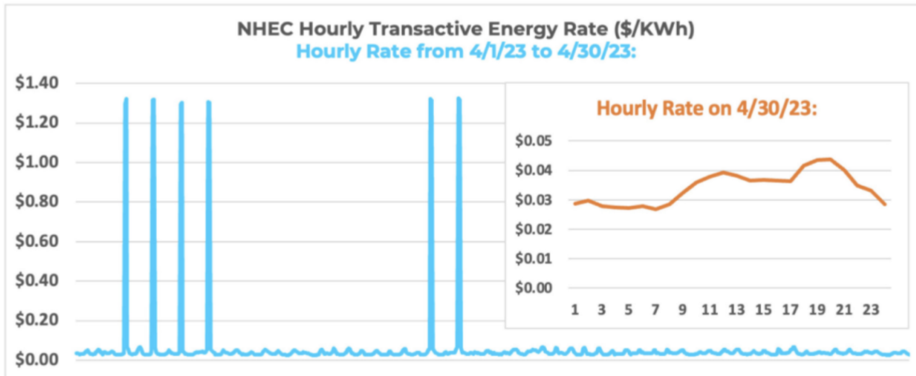
[7] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 21F, Eastern Massachusetts Cambridge Service Area Large General Service Rate G-3, at p. 2-3. Online:

	Service Area,[8] and South Shore, Cape Code & Martha's Vineyard Service Area[9] — with near-identical tariff language, as excerpted below: *"Customers taking service under this schedule may elect to be billed on the customer's demand at the time of the ISO New England regional network monthly transmission system peak (the Coincident Peak Demand) for the legacy NSTAR Electric system… The Coincident Peak Demand shall be determined by meter, each calendar month on a one-month lag basis and shall be the customer's coincident 60-minute kilowatt demand."* Note that the MA DPU was able to order the utility to pass through transmission costs to the larger customers because those classes have interval meters capable of measuring coincident peak demand. (Massachusetts has not deployed smart meters for the mass market.) Note also that the MA DPU did so without first seeking permission from FERC to change how retail customers were charged for transmission. **<u>New Hampshire</u>** Similarly, the New Hampshire Electric Co-op is allocated transmission revenue requirements on a '12 CP' basis. (I.e., the utility is allocated transmission costs based on their customers' share of demand at the time of coincident peak in each month.) In turn, the utility has chosen to offer a "Transactive Energy Rates" real-time pricing program that incorporates time-varying transmission price signals. Specifically, the utility forecasts the likelihood that the system peak will occur on various days throughout the month and passes through an appropriate price signal. Price signals throughout the month of April 2023 are shown below in blue; note that the large price spikes are due to the transmission price signal, and the prices on April 30th are provided in the accompanying graph (in orange) to show hourly prices on a day that did not include the transmission price signal:

https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/21-tariff-ma.pdf?sfvrsn=e57e110f_3

[8] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 13F, Eastern Massachusetts Greater Boston Service Area Large General Service Rate G-3, at p. 2-3. Online: https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/13-tariff-ma.pdf?sfvrsn=290ffbed_3

[9] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 31F, Eastern Massachusetts Cape Code & Martha's Vineyard Service Area, Large General Service Rate G-3, at p. 2-3. Online: https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/31-tariff-ma.pdf?sfvrsn=fe6e0fff_3



Note that it is a "prices to devices" program that leverages the submetering protocols developed by the CPUC in D. 22-08-024, and the NH Electric Co-op staff in charge of the program is former CPUC staffer Dave Erickson.

The rate is designed such that a device (an EV, battery, etc.) that responded to all six price spikes in April would capture almost the full value of the avoided transmission cost that would have otherwise been incurred by the utility.

Note that the utility did not have to first seek permission from FERC to change how transmission costs were recovered in retail rates.

For additional information and links, refer to UCAN comments filed July 28, 2023, pages 7-8, in Rulemaking 21-06-017 (High DER proceeding): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M515/K973/515973863.PDF

Pennsylvania

In PJM, 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."[10]

Consequently, in Pennsylvania, for example, 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 behalf of the customers that remain on utility default supply.[11] In fact, the Pennsylvania Public Utilities Commission recently reaffirmed that

[10] 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

[11] *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

	competitive suppliers should continue to decide how to charge transmission costs to customers, as opposed to having the utility recover all such costs via a nonbypassable charge, in part because competitive suppliers "have the freedom to build, establish, and promote innovative products and services to meet their individual customers' needs" and can manage customer loads.[12] Note here that the Commission's order — in the ~10 pages that discussed whether transmission costs should be recovered in a fundamentally different way from competitive supply customers — did not anticipate needing to seek FERC's permission. Additionally, transmission costs in PJM are allocated based on customer coincident demand net of BTM generation — and IFOM generation is allowed to be netted out as well, subject to certain conditions: 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****."*[13] PJM's OATT also provides that generation units which deliver energy to load across distribution facilities may qualify as "Behind the Meter Generation" (emphasis added): *"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***

[12] *Ibid.,* pp. 40.
[13] 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

	***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."*[14] 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 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 across the distribution grid (i.e., what is referred to as "in front of the meter" generation in California), 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).
Other Sections	On page 5, footnote 19, the Joint Utilities state that "The inclusion of marginal cost-based hourly pricing components for distribution and transmission in RTP offerings in the U.S. has not been proven…". This is a misstatement. As explained above, the New Hampshire Electric Co-operative passes through transmission costs in a real-time price signal. On page 19, the Joint Utilities state that "Although LMS-compliant Full-scale RTP rate proposals are not required until October 2025…" Similarly, page 20 represents that the "Joint IOUs are working on a path forward to be able to meet the LMS requirement to propose LMS-compliant Full-scale RTP rates by October 2025…" However, LMS standards (Section 1623, a, 2) require the Joint Utilities to apply to the CPUC for approval of "at least one marginal cost-based rate" for each customer class "[w]ithin twenty-one months of April 1, 2023". Twenty-one months from April 2023 is January 2025, not October. This date should be corrected, along with the timelines presented. Additionally, the LMS standards (Section 1623, d, 2) require the Joint IOUs to submit to the CEC "a list of load flexibility programs deemed cost-effective by the Large IOU" including at least one option regarding marginal cost rates or related marginal signals "that enable automated end-use response". This deadline should be incorporated into the timelines, along with further explication regarding the Joint Utilities proposed approach for compliance.

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

ATTACHMENT 2

R.21-06-017, UCAN comments in the High DER Future Proceeding, filed 28 July 2023

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	R.21-06-017 (Filed June 24, 2021)

COMMENTS OF THE UTILITY CONSUMERS' ACTION NETWORK (UCAN) ON ADMINISTRATIVE LAW JUDGES' MAY 9, 2023 RULING SETTING A WORKSHOP, ADMITTING INTO THE RECORD PART 1 OF THE ELECTRIFICATION IMPACTS STUDY AND RESEARCH PLAN, AND SEEKING COMMENTS

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July 28, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	R.21-06-017 (Filed June 24, 2021)

COMMENTS OF THE UTILITY CONSUMERS' ACTION NETWORK (UCAN) ON ADMINISTRATIVE LAW JUDGES' MAY 9, 2023 RULING SETTING A WORKSHOP, ADMITTING INTO THE RECORD PART 1 OF THE ELECTRIFICATION IMPACTS STUDY AND RESEARCH PLAN, AND SEEKING COMMENTS

I. INTRODUCTION

The Utility Consumers' Action Network (UCAN) submits the following comments and feedback in response to questions posed in the May 9, 2023, Administrative Law Judges' *Ruling Setting a Workshop, Admitting Into the Record Part 1 of the Electrification Impacts Study and Research Plan, and Seeking Comments* (May 9, 2023, Ruling), regarding the *Electrification Impacts Study Part 1: Bottom-up Load Forecasting and System-Level Electrification Impacts Cost Estimates* (Part 1 Study).

UCAN's primary recommendation is for Energy Division to convene a workshop to confirm and discuss how Kevala proposes to (1) incorporate technology cost curves into the adoption forecasts, and related technology-related methodological refinements, and (2) forecast and thereafter adjust customer rate levels accordingly. As explained below, UCAN believes that integration and co-optimization of Kevala's pioneering 'bottom up' model with extant 'top down' production cost, generation capacity, and transmission planning models is actionable, warranted, and necessary to forecast future rates and thereby enable accurate simulation of the technology and rate scenario analyses proposed by Kevala for the Part 2 Study.

II. FEEDBACK ON THE PART 1 STUDY AND QUESTIONS

UCAN commends Kevala and the Energy Division for the release of the Part 1 Study. The premise-level forecast methodology has the potential to yield meaningful insights regarding the impact of new policies and rate designs in terms of system benefits, customer bills, and equity— across 12 million premises statewide. UCAN believes that these simulation capabilities will prove to be a critical tool for seeing 'over the horizon' and ultimately enabling an affordable energy transition for ratepayers during a period of fundamental change and uncertainty.

UCAN also appreciates the subsequent work on the part of the Public Advocates Office (PAO) and Investor Owned Utilities (IOUs), particularly PG&E and SCE, in assessing Kevala's novel methodology, identifying areas of improvement and open questions, and contemplating how a bottom-up approach could best be used to inform utility planning processes. UCAN is confident that these efforts will yield a refined baseline and accepted methodology on which to contrast policy-driven scenarios in the Part 2 Study.

In particular, UCAN supports the proposed incorporation of DMV vehicle registration and natural gas customer usage and billing data,[1] and notes SCE's recognition that accessing the same data would enhance the utility's own DER forecasts as well. [2] These improvements should provide valuable clarity into primary drivers of the locational grid impacts associated with transportation and building electrification, respectively.

UCAN also concurs with PG&E that the "impacts of broader vehicle-grid integration strategies" should be included in the Part 2 Study, given that "smart charging, bidirectional charging, Real Time Pricing, and demand response programs will play a significant role in

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[1] Part 1 Study p. 80, 126
[2] SCE Comments and Responses, p. 14.

shaping future EV load profiles – notably by way of load shifting to mitigate stress on the grid over a 2035 time horizon."[3]

More broadly, regarding rate and technology scenarios proposed by Kevala for Part 2, UCAN strongly supports inclusion of "real-time hourly rates, advanced, high-penetration demand response (>75% penetration of air conditioning load control, heat pumps, heat pump water heaters); and vehicle-to-grid adoption for MDV/HDV ZEVs".[4]

However, relevant here is that the Part 1 Study is less a forecast of DER adoption, and more an analysis of where IEPR-forecasted DER is likely to be physically located across the distribution grid over the forecast horizon.[5] Consequently, various methodological changes will be necessary to enable policy-driven scenario analysis for the Part 2 Study.

Most notably, in this context, UCAN shares SCE's concern[6] that the initial Part 1 Study results are based on assuming that rates, DER prices, and DER payback periods remain constant through the forecast horizon based on 2022 values.[7] UCAN observes here that:

- The Commission previously forecasted that rates would be increasing between now and 2030 — and UCAN observes that this was prior to the release of the Part 1 Study (indicating significant unplanned distribution investments) as well as the CAISO 20-Year Transmission Outlook (forecasting $30.5 billion of transmission investments needed to meet the state's 2045 clean energy goals) [8] — across all three IOUs to varying degrees, as

[3] PG&E Comments and Responses, p. 13.
[4] Part 1 Study, p. 131.
[5] With the apparent exception of the peak load impacts of electric vehicles, which PAO and SCE recommend should be calibrated to reflect IEPR forecasts; here, UCAN observes that Pub. Res. Code § 25301(e) provides that (emphasis added), *"If an entity listed in this subdivision [including the PUC] objects to information contained in the [IEPR] report and **has a reasonable basis for that objection**, the entity shall not be required to consider that information in carrying out its energy-related duties."*
[6] SCE Comments and Responses, p. 9
[7] Part 1 Study, p. 7.
[8] CAISO 20-Year Transmission Outlook, p. 57. Online: https://www.powermag.com/wp-content/uploads/2022/02/draft20-yeartransmissionoutlook.pdf

well as for natural gas and gasoline, causing customer energy bills to rise above the rate of inflation.[9]

- Simultaneously, the price of DER is forecasted to decline [10] and the value is generally expected to increase over time (particularly for demand flexibility and dispatchable DERs, assuming a framework that intelligently orchestrates and fairly compensates resources for creating system benefits in an environment of increasing volatility).

The combination would indicate that payback periods will continue to decrease, depending on the scenarios modeled, which would reasonably be anticipated to impact the rate and extent of adoption. This becomes critically evident when considering how to produce policy-driven scenario analyses:

- It would not be realistic if, for example, a real-time rate structure was simulated, and demonstrated to increase the system value created and monetized by DERs, but that this change yielded no decrease in assumed DER payback or corresponding increase in DER adoption.
- In turn, it would not be realistic to ignore the system value created by adoption of real-time rates — given that DERs would be dispatched, and load flexed, presumably in response to price signals incorporating energy and generation, distribution, and transmission capacity constraints — which would, at scale, lower system costs and therefore customer rate levels below the baseline forecast.

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[9] CPUC, Utility Costs and Affordability of the Grid of the Future, May 2021, pp. 4-6. Online: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf

[10] *See* Wood Mackenzie, "US Distributed Energy Resource market to almost double by 2027" (20 June 2023).. Online: https://www.woodmac.com/press-releases/us-distributed-energy-resource-market-to-almost-double-by-2027/

However, the extent to which Kevala intends to update these assumptions in the Part 2 Study is unclear. The Part 1 Study variously indicates that both the cost of DERs and future rate levels were (emphasis added) "in development [and therefore were assumed to be] constant 2022 values over time ***for the purposes of the Part 1 analysis***"[11] — similarly, the research plan indicated that "technology cost curves" would be an input into the DER adoption simulations[12] — but also that "regarding where IOU rates and costs will go in future years is ***outside the scope of this study***; as a result, rate increase assumptions will mirror cost changes in DERs generally."[13]

UCAN recommends that Energy Division convene a workshop to confirm and discuss how Kevala proposes to (1) incorporate technology cost curves into the adoption forecasts, and related technology-related methodological refinements,[14] and (2) forecast and thereafter adjust customer rate levels accordingly, to permit policy-driven scenario analysis.

UCAN cannot see how the rate and technology scenarios proposed for Part 2 could be realistically simulated by Kevala without these structural expansions of the methodology — particularly given that the policy scenarios should align with and reflect the rate design and demand flexibility tariff principals ordered by the Commission in Decision 23-04-040, incorporating marginal cost-based compensation for (emphasis added) "***energy, generation capacity,*** distribution capacity, ***and transmission capacity based on grid conditions.***"[15]

[11] Part 1 Study, p. 7.
[12] *See* May 9 Ruling, Attachment 3, submitted by Kevala, Inc. to CPUC on March 29, 2022, Electrification Impacts Study Research Plan (Research Plan), p. 16.
[13] Part 1 Study, p. 12, fn 49.
[14] *E.g.,* incorporation of payback periods for battery storage adoption (which are currently disregarded in the adoption analysis), hourly impacts of energy efficiency measures (currently applied equally on an equal percentage basis to every hour in the year), demand response (the potential for which is currently disregarded, beyond what is currently assumed in 'business as usual' utility programs and peak load forecasts), etc.
[15] *See* R.22-07-005, D.23-04-040 (April 27, 2023), p. 37, including that (emphasis added) "[d]ynamic prices should, to the extent feasible, accurately ***incorporate the marginal costs of energy, generation capacity,*** distribution capacity, ***and transmission capacity based on grid conditions***" and *"[d]emand flexibility tariffs should* ***provide***

UCAN observes here that Kevala's literature review was apparently confined to studies previously conducted in the United States.[16] UCAN's Opening Comments on the OIR noted how Australia "simulated a nationwide, 100% decarbonization by 2050 scenario. The methodology appears to co-optimize in a 'bottom up' and 'top down' fashion (e.g., incorporating customer usage data, circuit and substation topologies to capture network deferrals, while simulating wholesale dispatch and capacity expansion)", the conclusions of which "demonstrated how relying upon retail demand flexibility and DERs to decrease the level of distribution grid investments that would otherwise be required to accommodate Australia's energy transition, the financial benefits created from participating DER customers were sufficiently large such that nonparticipating customers (low-income, etc.) would pay lower costs overall as well." — and how Australia had gone on to deploy local flexibility market platforms to enable their energy transition.[17]

In advance of the workshop, UCAN recommends that Energy Division task Kevala with understanding how the 'bottom up' and 'top down' modeling was integrated to produce the Australian study, for presentation and discussion with parties. UCAN observes that the requisite 'top down' models (e.g., production cost, capacity expansion, and transmission planning models) are already in-use today. A discussion of how best to integrate and co-optimize these simulations with Kevala's pioneering approach to 'bottom up' policy-driven scenario analysis — apart from being necessary to enable realistic technology and rate scenarios — could yield a truly holistic approach to simulating California's high distributed energy resource future.

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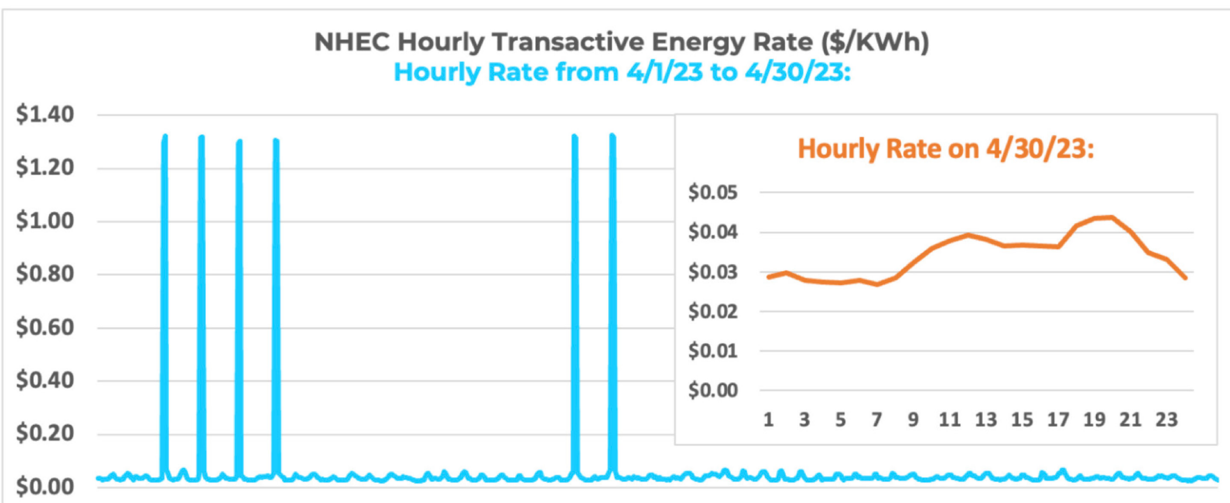
marginal cost-based compensation *for exports to enable economically efficient grid integration of customer-sited electrification technologies and distributed energy resources*." Online: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K837/507837776.PDF

[16] Part 1 Study, pp. 14-15.

[17] UCAN Opening Comments on OIR, 6 August 2021, pp. 13-15. Online: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M399/K245/399245064.PDF

As a relevant aside, and illustrative example of a comparable new rate scenario for consideration, UCAN observes that the New Hampshire Electric Co-op has recently deployed Transactive Energy Rates, in part by leveraging the submetering standards adopted by the Commission in D. 22-08-024 — including by passing through transmission price signals to incent electric vehicle and onsite storage resources — and has estimated that "home storage systems could save ~$1,200 per year, fully electrified homes could save approximately $3,600 per year, and EVs could generate between $3,500 and $4,500 per year (depending on whether a 15KW or 20KW charger, respectively, is used)" due to the resulting magnitude of the real-time price signals: [18]



Here, UCAN emphasizes the magnitude of price signals capable of incenting demand flexibility and DERs, and observes that the significant bill savings estimated for participating customers would significantly shorten the payback periods — thereby increasing DER adoption rates. Deployed on a wide scale, such an approach would stimulate customer investment decisions and demand flexibility to a degree that could create tremendous, new system-wide

[18] *See* New Hampshire Public Utilities Commission, IR 22-076, Community Power Coalition of New Hampshire Final Comments. Online: https://www.puc.nh.gov/regulatory/Docketbk/2022/22-076/LETTERS-MEMOS-TARIFFS/22-076_2023-06-13_CPCNH_FINAL-COMMENTS.PDF

benefits — thereby lowering average rates for customers while helping to ensure system reliability system-wide (e.g., across generation, distribution, and transmission).

III. CONCLUSION

UCAN again applauds Kevala and Energy Division for pioneering a 'bottom up' modeling approach for California's high DER future and looks forward to working with parties to refine and expand upon the methodology to enable policy-driven scenario analyses capable of simulating the co-optimizations across generation, distribution, and transmission capacity constraints that will be critical to achieving state policy goals and ensuring energy affordability for California's ratepayers.

Respectfully submitted,

<u>/s/ Jane Krikorian</u>

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Dated: July 28, 2023

ATTACHMENT 3

NHPUC IR 22-076, Community Power Coalition of New Hampshire comments, filed 13 June 2023

BEFORE THE PUBLIC UTILITIES COMMISISON
STATE OF NEW HAMPSHIRE

IR 22-076

ELECTRIC DISTRIBUTION UTILITIES

Investigation of Whether Current Tariffs and Programs are Sufficient to Support Demand Response and Electric Vehicle Charging Programs

June 13, 2023

COMMUNITY POWER COALITION OF NEW HAMPSHIRE

FINAL COMMENTS

The Commission opened IR 22-076 on November 15, 2022, to investigate compliance with the Infrastructure Investment and Jobs Act ("IIJA"), codified as 16 U.S.C. § 2621, and to "consider whether to adopt rate mechanisms or standards concerning such demand response practices and electric vehicle charging programs" pursuant to the directives of 16 U.S.C. § 2621(b), (c), and (d)(20)-(21). The Commission solicited responses to a set of questions relating to these matters, that it intends to consider as part of a future adjudicative proceeding, including:

- What market barriers exist that, to date, have prevented greater demand response management?
- Should New Hampshire continue to leverage the current Electronic Data Interchange (EDI) paradigm, or should a new standard be used?
- What structural reforms could enable a more competitive retail electricity market in New Hampshire and within ISO-NE?

The Community Power Coalition of New Hampshire (CPCNH) provides these final comments in response to the initial and reply comments filed by parties in this proceeding.

We appreciate the insightful and broad scope provided for by the Commission and hope that our contributions to the record go some way towards delivering upon what was requested of the parties to this investigation, with particular reference to the above-cited questions.

1. Introduction

CPCNH, as summarized in our Reply Comments,[1] is a power agency that is fully capable of offering advanced rates and products to customers, which will serve more customers than any other competitive supplier in New Hampshire, with a larger default customer base than either Unitil Corporation or Liberty Utilities.

To supplement and provide additional context for these comments, CPCNH has attached complaint filings recently submitted to the Commission and DOE detailing how Eversource is in violation of Puc 2200 administrative rules (regarding provision of services to Community Power Aggregators, "CPAs"), Order No. 22,919 (5/4/98), RSA 53-E, RSA 362-A:9, II and RSA 374-F:3, XII(c) as well as the express intent of RSA 374-F. Eversource's acts and omission of actions in violation of these laws and PUC order have substantially delayed the launch of CPCNH's power supply service — at the cost of an estimated $4,380,000 in foregone cost savings for New Hampshire ratepayers and communities — and foreclosed CPCNH's ability to offer net metering or advanced rate structures and programs, including to enable demand response and rates to encourage electric vehicle adoptions, to customers on CPA service.

Initiating Community Power supply service has been educational, in terms of providing a clear view of the various structural ways in which utilities have failed to fully enable competitive provision of retail services to customers— and have therefore hampered or entirely foreclosed non-utility provision of, for example, demand response and electric vehicle services.

CPCNH therefore focuses these Final Comments not on specific technologies, or one-of-a-kind products and program design initiatives, but rather the more holistic and structural alignments that will be necessary to enable the provision of retail innovation — inclusive of demand response and electric vehicle services — more broadly. Our recommendations, in part, reference and draw upon the complaints incorporated hereto for the Commission's consideration.

[1] CPCNH Reply Comments, pp. 1-3.

2. Meter Data Management, Billing, and ISO-NE Settlement Services

CPCNH finds that Reply Comments by Eversource[2] and Unitil Corporation[3] regarding consideration of issues relating to Electronic Data Interchange (EDI) and related services are informative but fall short of providing the Commission with sufficient context to inform the purpose of this investigation as it pertains to scoping out structural reforms to enable the competitive market to offer new retail products.

The practical process of retail product innovation (e.g., demand response and electric vehicle rates and services) requires CPAs and CEPS to perform a linear and inter-related sequence of steps across the "retail value chain", which refers to the infrastructure and business processes that span customer-facing functions (metering, data management, rate structures, billing and customer engagement) and flow into wholesale market and network integration functions (e.g. settlement profile construction, non-utility consolidated billing protocols, interconnection standards, integrations to and from Meter Data Management Systems, MDMS, and Advanced Distribution Automation Systems / Distributed Energy Resource Management systems, ADMS / DERMs, etc.).

Non-provision or misalignments of the underlying utility services required to carry out any of these different functions in the retail value chain will foreclose (preclude or raise the cost of to an un-economic degree) market innovation, as a problem in one step will cause unintended consequences or fully block progress in other steps.

This is precisely what has happened in New Hampshire. CPCNH's complaints detail how Eversource's tariff and supplier service agreements deviate from NH EDI requirements, in interrelated ways that make it practically impossible for CEPS and CPAs to fully serve NEM and TOU customers from an operational perspective. We plan to file complaints to address the similar, often identical, violations by Liberty Utilities and Unitil Corporation.

CPCNH, in joint comments filed with the Office of the Consumer Advocate (OCA) and Clean Energy New Hampshire (CENH), first brought this matter to the Commission's attention during the CPA rulemaking: " . . . all of the utilities' competitive supplier agreements and

[2] Eversource Reply Comments, pp. 3-5.
[3] Unitil Reply Comments, pp. 2-3.

associated terms and conditions appear to be non-compliant with the standards and guidelines made by the Electronic Data Interchange Working Group report made effective by PUC Order No. 22,919 (May 4, 1998) and other applicable regulations of the PUC. [Footnote: *See* PUC Order No. 22,919: https://www.puc.nh.gov/regulatory/Orders/1998ords/22919e.html. *See also* EDI Standards: https://www.puc.nh.gov/electric/edi.htm]."[4]

On that basis, CPCNH, OCA and CENH also urged the Commission to reconvene the NH EDI Working Group.[5] More recently, and citing to CPCNH data request responses from Unitil, the NRG Retail Companies (representing Direct Energy Services, LLC; Direct Energy Business, LLC; Direct Energy Business Marketing, LLC; Reliant Energy Northeast LLC; and XOOM Energy New Hampshire, LLC) protested against Unitil's non-compliance with NH EDI Standards and called upon the Commission to "reconstitute the New Hampshire EDI Working Group, and require [Unitil] to complete the appropriate change control process and related protocols germane to the State of New Hampshire."[6]

CPCNH appreciates that the Commission included consideration of EDI, and of the broader structural reforms required to enable a more competitive retail electricity market, in this investigation. When establishing the subsequent adjudicative docket, CPCNH recommends that the Commission consider:

- How to structure the NH EDI Working Group, which should be reconvened as soon as possible, including consideration of:
  - A compliance review regarding the various ways in which the utilities current practices diverge from NH EDI standard requirements;
  - Responsibilities for the Working Group extending beyond EDI into the related business process and technical areas of utility service required to enable retail innovation in practice (e.g., to permit identification and resolution of barriers to

[4] Docket # 21-142, CPCNH Reply Comments, p. 26. Available online: https://www.puc.nh.gov/regulatory/Docketbk/2021/21-142/LETTERS-MEMOS-TARIFFS/21-142_2022-03-28_CPCNH_OCA_CENH-COMMENTS.PDF
[5] *Ibid.*, p. 31.
[6] Docket # DE 23-002, NRG Retail Companies Comments, pp. 8-9. Available online: https://www.puc.nh.gov/regulatory/Docketbk/2023/23-002/COMMENTS/23-002_2023-06-09_NRG_COMMENTS.PDF

customer services that EDI should enable, but cannot at present, due to non-alignments in utility Meter Data management Systems, billing / Customer Information Systems, ISO-NE settlement services, etc.); and

  - Implementation of mechanisms to monitor and ensure that the utilities maintain compliance going forward.

- How to standardize the utilities' tariffs and supplier service agreements regarding provision of services to CEPS, including to incorporate and comply with Puc 2200 rules and the requirement that CPAs should be able to register as suppliers with the utilities; this should include a compliance review focused on the various instances in which:
  - Current utility business practices do not provide the level or scope of services the utility is committed to supporting pursuant to their tariffs and/or service agreements; and
  - Utility tariffs and/or supplier service agreements conflict with statutory and rule requirements and prior Commission orders, both on an individual basis and when considered side-by-side (e.g., because there are instances where the tariffs may appear compliant but service agreements — which may not have been previously approved by the Commission — render the utility non-compliant).

- How the different Meter Data Management Systems (MDMS) or metering information database of each utility could be leveraged to provide alternative means of meter data access to CPAs and CEPS, initially by confirming what each is <u>functionally</u> capable of enabling in this regard. This should be considered, in part, in the context of the above recommendations. For example, since utilities are not transmitting time-of-use period usage and excess generation / negative usage data to CPAs and CEPS via EDI (and may continue to represent that this data isn't readily available in their billing systems), configuration of routine, one-way transmittals of this data directly from the MDMS to one or more secure servers configured for permissioned access by (and potentially hosted by) CPAs and CEPS may prove to be the more cost-effective and expeditious means to enable transmission of interval data, potentially for lower-latency transmittal (e.g., day after, intra-day, etc.) of more 'real time' data as the NH retail market evolves over time.

CPCNH is prepared to devote technical resources in the forthcoming proceeding, drawing upon the service providers and staff experts operating our power agency to ensure that the Commission is provided with a holistic view of the realignments and structural reforms — across the interrelated functional aspects of the competitive retail and wholesale market structures — that will be necessary to enable CPAs and CEPS to offer innovative rates and products to all customers in New Hampshire.

3. Enabling Transactive Energy Rates

CPCNH believes that Transactive Energy Rates could be deployed over the relative near-term to broadly incentivize demand flexibility on a year-round basis across New Hampshire. To date, utility comments have framed the opportunity for demand flexibility as mostly available during only the summer peak months. Eversource's comments on CLF's suggestion of targeting peaks during non-summer months suggested that there is "little to no system or ratepayer benefit" associated with demand response except during "summer-peaking months." They continued to caution that one of the utility's affiliates "ran a winter DR program in Massachusetts for two seasons in 2019-2020 and 2020-2021, but it ceased to offer the program after that because it was not cost-effective."[7]

CPCNH views Eversource's demand response program design as artificially constrained, by focusing only on generation capacity savings, and as such, economically disadvantageous for customers. Similarly, in response to party comments that view utility managed charging as the only means to manage or mitigate distribution grid upgrades driven by EV load growth, CPCNH opposes such utility proposals at this time, concurs with OCA's caution that "not all customers will be amendable to having the utility control their EV charging equipment through a managed charging program", and generally cautions the Commission and all parties against continuing to rely upon utilities, rather than the market, to determine the pace and extent of retail innovation.

Given the need to more holistically enable demand flexibility, including for customers (with or without EVs) served by CPAs and CEPS, CPCNH agrees with OCA, as well as CLF and Unitil, that the Commission should adopt "standards to address 16 U.S.C. § 2621(d)(20)(A) or (B)(i) related to "promote the use of demand-response and demand flexibility practices by

[7] Eversource Reply Comments, p. 2.

commercial, residential, and industrial consumers to reduce electricity consumption during periods of unusually high demand" and to "establish rate mechanisms allowing an electric utility subject to the Commission's ratemaking authority to timely recover the costs of promoting demand response and demand flexibility practices."[8]

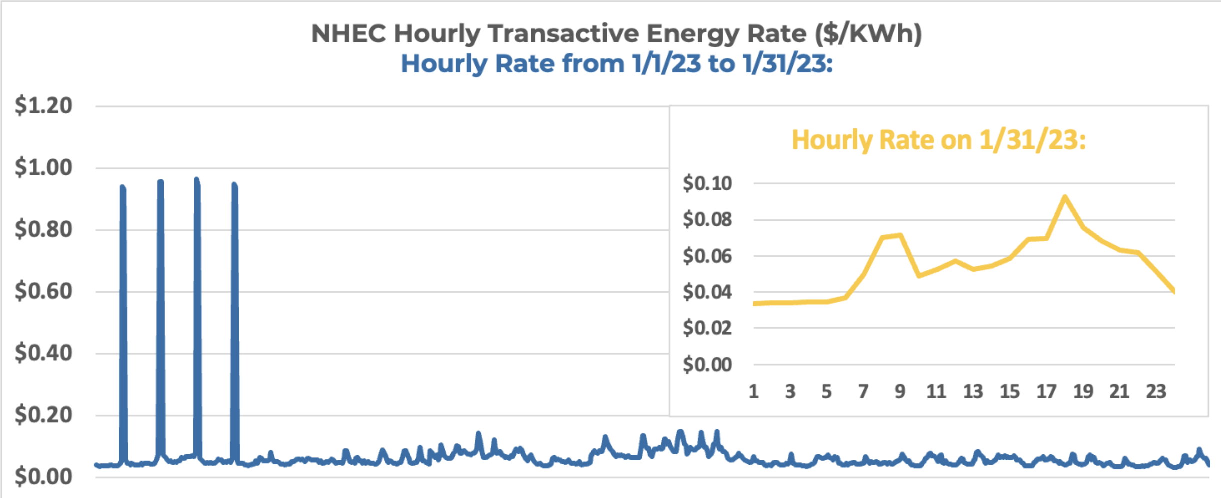
CPCNH also strongly concurs with OCA's subsequent recommendation that the state should leverage the advanced monitoring and control technologies embedded in EVs and EV supply equipment (EVSE), coupled with time-varying price signals, to maximize price-responsive demand flexibility to lowers system costs for all ratepayers.[9]

Building upon OCA's recommendation, CPCNH observes that the New Hampshire Electric Co-op (NHEC) recently deployed a Transactive Energy Rate (TER) pilot program, under which controllable devices, rather than entire homes and businesses, can be selectively exposed to retail rates that vary by hour.[10] To do so:

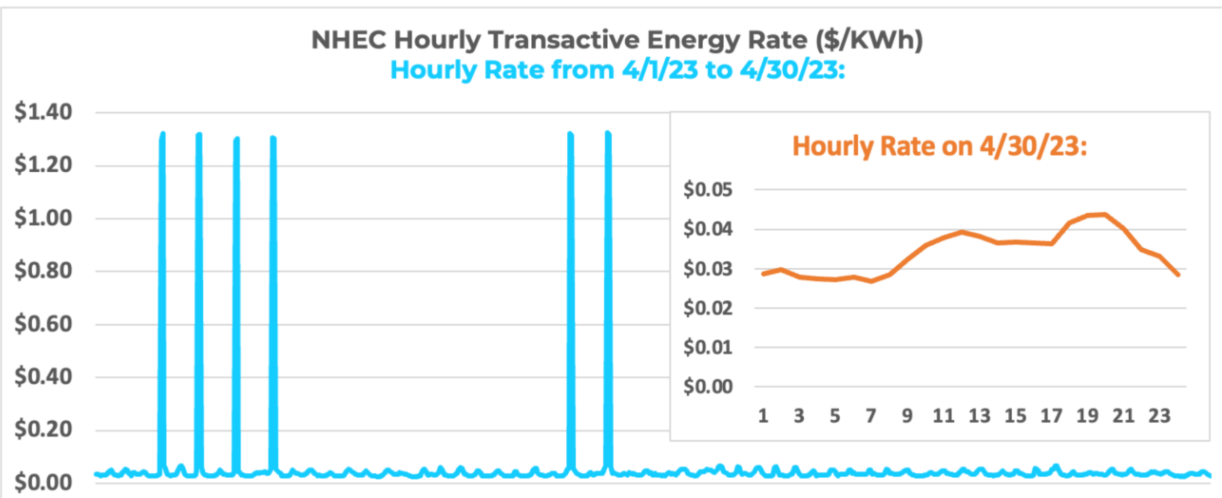
- NHEC is leveraging submetering and communication protocols recently developed in California[11] to access and rely upon the submetering capabilities built into EV / EVSE, home battery storage systems, and additional devices as the program evolves (such as heat pump water heaters, and smart panels connected to a variety of appliances); and
- NHEC is passing-through transmission cost price signals on an hourly basis along with wholesale energy and generation capacity prices.

As shown in the graphs below, the inclusion of transmission price signals is critical to incentivizing demand flexibility year-round, including in the winter and shoulder season months:

[8] OCA Reply Comments, p. 2.
[9] OCA Reply Comments, pp. 4-5.
[10] NHEC Transactive Energy Rate: https://www.nhec.com/energy-management/transactive-energy-rate-program/
[11] CPUC Press Release: https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-decision-makes-california-first-state-in-the-nation-to-allow-submetering-of-electric-vehicles#:~:text=The%20California%20Public%20Utilities%20Commission,a%20technology%20known%20as%20submetering.



In the graph above, the average rate across all 744 hours in January of 2023 was $0.07 per KWh (7 cents/KWh). For the 4 instances of high-priced periods (each lasting for two consecutive hours), the average rate rose to $0.95 per KWh. Excepting the high-priced periods, the residual average rate for the month dropped to $0.061 per KWh.



In the graph above, the average rate across all 740 hours in April 2023 was $0.059 per KWh (5.9 cents/KWh). For the 6 instances of high-priced periods (each again lasting for two consecutive hours), the average rate rose to $1.31 per KWh. Excepting the high-priced periods, the residual average rate for the month dropped to $0.038 per KWh.

As context, transmission costs are allocated to utilities based on demand coincident with network peaks each month. However, at present, New Hampshire's investor-owned utilities recover the costs by charging customers volumetric rates for transmission that are flat year-round completely obscuring the "wholesale" marginal cost price signal. In contrast, NHEC has instead been forecasting when monthly network peaks are likely to occur, and passing through a series of hourly price signals that combine to reflect actual avoided transmission costs. In other words, devices that respond to all six $1.00 per KWh price spikes in the graphs above would capture the avoided cost of transmission set during the hour of peak demand within the month.

NHEC's approach to enabling demand flexibility offers a number of compelling advantages for customers, in terms of capital efficiency, and from a market design perspective:

- Customers are fully empowered, in terms of controlling what level of their usage to expose to time-varying prices, and protected, in that price exposure is limited to devices with embedded monitoring and intelligent controls — which mitigates the risk of being 'bill shocked' by unexpectedly high usage in a given month (e.g., due to a broken well pump, or leaking water heater, using significantly more electricity than expected, etc.).
- Transactive Energy markets can be opened without waiting or paying for utilities to roll-out Smart Meters and the accompanying Advanced Metering Infrastructure.
- Customer funds that would otherwise go towards paying for system costs are instead diverted to pay back the cost of customer-owned devices and EVs: NHEC estimates that home storage systems could save ~$1,200 per year, fully electrified homes could save approximately $3,600 per year, and EVs could generate between $3,500 and $4,500 per year (depending on whether a 15KW or 20KW charger, respectively, is used).
- NHEC, as a distribution utility, does not need to invest in the expertise and complexities required to directly control devices, or 'get into the business' of engaging and educating customers directly; instead, aggregators and distributed energy companies are relied upon to do so — and to figure out how to deploy more cost-effective technologies and services for customers – while the utility focuses on maintaining the "poles and wires".
- Non-participating customers also benefit financially, because flexing demand and dispatching storage / generation across multiple hours of high network demand each month (rather than only for the peak hour of system demand in summer) will also lower distribution costs over time.

CPCNH observes here that Eversource, Liberty Utilities, and Unitil Corporation have all deployed, or previously proposed deploying, utility-owned solar and storage projects or utilityadministered customer device programs that capture and monetize the same avoided benefits of energy, generation capacity, and transmission charges:

- Liberty Utilities: for their Battery Storage Pilot customer program, now proposed for expansion in DE 23-039 (the utility's distribution rate case).
- Unitil: for the utility-owned ~4.9 MW battery storage project approved in DE 22-073.
- Eversource: for their Westmoreland Energy Storage Pilot proposal (though the proposal was later withdrawn by the utility, and never built).[12]

A corollary observation is that the calculations and business process changes required to enable Transactive Energy Rates are in fact well established, understood by each utility, and should be readily leveraged to enable CPAs and CEPS to enable demand flexibility — in the same way that NHEC has already done for its customers — for customers on competitive supply.

In fact, this is precisely what will be required to support the CPA and CEPS pilots called for under RSA 362-A:2-b. Pending the resolution of Docket No. DE 23-026, if the PUC determines that it has the same jurisdictional authority other New England states have acknowledged to direct the investor-owned utilities to support market-based compensation for CPAs and CEPS that aggregate customer devices (or contract for distribution-interconnected battery and generation projects) under 5 MW in total capacity, then the next step will be to determine how actual avoided costs will be credited or realized on an operational basis for the pilots.

CPCNH recommends that this be determined by the Commission generically, in a standardized fashion for all projects, either ahead of any pilot proposal (as the utilities initially proposed in IR 22-061 at the pre-hearing conference), or the first time a pilot proposal is submitted to the PUC pursuant to RSA 362-A: 2-b, XI(a). In either case, the calculations required will be straightforward and standardized, such that the utilities should be expected to implement compensation mechanisms (for CPAs and CEPS that extend time-varying rates to

[12] Docket DE 19-057, Eversource Attachment GTEP-3, available online: https://www.puc.nh.gov/regulatory/Docketbk/2019/19-057/INITIAL%20FILING%20-%20PETITION/19-057_2019-05-28_EVERSOURCE_ATT_DTESTIMONY_ANCEL_SCHILLING.PDF

customer devices) that are automated or else require minimal and infrequent manual actions on the part of the utilities:

- The value of energy is realized by the impact of metered output of a pilot on load settlements, which are computed on an hourly basis each day. Utilities are already required to perform this calculation for third-party suppliers that serve net metered customers, to properly account for any excess generation as a reduction in the supplier's net load obligations,[13] and adjusting the settlement processes to also net out the metered energy generated by pilots should not incur much additional expense.
- The value of avoided transmission charges are computed as (1) the metered exports of a pilot to the distribution grid at the monthly hour of system peak multiplied by (2) the RNS and LNS rates (which allocate transmission cost at the hour of monthly peak load across the networks). That could be 12 to 24 calculations per year per pilot (depending on whether monthly RNS and LNS network coincident peaks are coincident with each other or not). There are two mechanisms provided for enabling proper compensation pursuant to RSA 362-A:2-b, XI(a):
    - The first compensation mechanism would continue to charge all ratepayers the same volumetric transmission rates, which would be computed by the utility as though the pilots had not lowered peak demand, to collect additional funds that would then be transferred from the utility to the CPAs / CEPS participating in the pilot.
    - The second compensation mechanism is more efficient and aligned with market principals, in that customers on utility default service would continue to be charged for transmission by utilities without any change in the process thereof, while customers served by CPAs / CEPS participating in the pilot would begin being charged for transmission by their CPAs / CEPS directly. The utility would assign transmission charges to the CPA / CEPS to factor into customer billing, based on their customer demand obligations and subtraction of the metered generation output of the pilot to the distribution grid at the time of the monthly

[13] RSA 362-A:9, II

peak. CPAs/CEPs could also invoice utilities for the benefits that were realized from the peak load reduction after the fact (one to two months later). **CPNCH observes here that this mechanism would have the additional potential benefit of enabling CPAs and CEPS to charge transmission rate components on a time-varying basis to customer devices — and enable market-based demand flexibility in the same way that NHEC has done.**

- For determining avoided capacity costs, the calculation is based on a single metered measurement of exports to the distribution grid at the annual hour of regional coincident peak demand. Utilities would need to adjust the ICAP tags of retail customers served by the CPAs / CEPS participating in the pilot, once per year.

On the basis of the foregoing, CPCNH recommends that an adjudicative docket subsequent to this investigation determine:

- Whether the submetering and communication protocols that NHEC has adopted for its Transactive Energy Rate program should be adopted and relied upon across the service territories of Eversource, Unitil, and Liberty Utilities, or whether an alternative protocol should be authorized to enable device-level submetering; and
- How actual avoided costs will be credited to or otherwise realized by CPAs and CEPS that aggregate customer devices (or contract for distribution-interconnected battery and generation projects) under 5 MW in total capacity as net load reducers, and the timeline by which Eversource, Unitil, and Liberty Utilities will be required to implement the changes required to enable the market mechanisms provided for under RSA 362-A:2-b.

Pending resolution of the above two requirements to open the market, CPCNH is prepared to follow NHEC's lead in offering opt-in Transactive Energy Rates for customers on CPA supply service throughout New Hampshire.

4. Conclusion

Thank you for the consideration of CPCNH's recommendations. The solutions that are coming into focus here are actionable and will no doubt begin the process of a tremendously advantageous and powerful market transformation for New Hampshire.

Our expanding membership of 35 communities, each of which has appointed representatives to actively engage in governing our power enterprise, appreciates the Commission's continuing focus on enabling Community Power Aggregators to "encourage voluntary, cost effective and innovative solutions to local needs with careful consideration of local conditions and opportunities" with the objective of providing "small customers with similar opportunities to those available to larger customers in obtaining lower electric costs, reliable service, and secure energy supplies", as the Legislature originally intended.[14] More broadly the Commission has the opportunity here to better "reduce costs for all consumers of electricity by harnessing the power of competitive markets" and expand "markets for new and improved technologies" by providing "electricity buyers and sellers with appropriate price signals" as called for by RSA 374-F:1.

I look forward to working collaboratively throughout the forthcoming adjudicative proceeding to make that vision a reality, most of all by leveraging our newfound capabilities as the largest and most competitive designed power enterprise in the state in all the ways needed to ensure that utility services are realigned to enable an innovative competitive market for services that create opportunities and new value for our customers, communities, and ratepayers as a whole.

Community Power Coalition of New Hampshire

Clifton Below

by CPCNH Chair Clifton Below

Attachments:

1. CPCNH Complaint to PUC Against Public Service Company of New Hampshire d/b/a Eversource Energy (June 13, 2023).
2. Exhibits to CPCNH Complaint to PUC Against Public Service Company of New Hampshire d/b/a Eversource Energy.
3. CPCNH Complaint to DOE Against Public Service Company of New Hampshire d/b/a Eversource Energy (June 13, 2023).

[14] RSA 53:E-1, Statement of Purpose.