Before the New Hampshire Public Utilities Commission

DE 24-070
Public Service Company of New Hampshire d/b/a Eversource Energy

Request for Change in Distribution Rates

Community Power Coalition of New Hampshire Data Requests Set 1 for Eversource

November 15, 2024

The Community Power Coalition of New Hampshire ("CPCNH"), by CPCNH Chair, Clifton C. Below, serves the following Data Requests on Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource").

1. If there are any questions regarding the data requests below, please contact Clifton C. Below, CPCNH Chair, at 603-667-7785 or Clifton.Below@CommunityPowerNH.gov.
2. If information fully responsive to the questions below is not available, please so state, explain why that information is not available, and provide the closest possible approximation of a fully responsive answer.
3. To the extent that a question below inadvertently duplicates or overlaps with another party's data request, please provide a cross-reference. Please provide a separate response as to any areas of divergence from the other party's question.
4. If any information requested is already publicly available, please provide a URL or other direct means to access the information.
5. If there is an objection to any data request, please state the basis of the objection. If the objection is based on privilege, identify the privilege and the facts on which privilege is based. If a claim of privilege is asserted with respect to a document, provide the date, title or number of the document, the identity of the person who prepared or signed it, the identity of the person to whom it was directed, a general description of the subject matter, the identity of the person holding it and the location of its custody. If any document requested has been destroyed, lost or is otherwise unavailable, please list and identify the document, describe the document with as much detail as possible, and state the circumstances of its loss, destruction or unavailability.
6. For each response, please identify the person who provided the response and who will be responsible for testimony concerning each request. Also, for each response, identify each individual who supplied any information in response to the question.
7. Please furnish data responses by the date provided in the procedural schedule in this docket; *i.e.*, by November 27, 2024.

Definitions

1. The word "document" means all writings of any nature whatsoever and all non-identical copies and drafts thereof, in your possession, custody or control, regardless of where

located, and without limitation the following items, whether printed or recorded or filmed or reproduced by any other mechanical or electrical process, or written or produced by hand, including but not limited to agreements, contracts, memoranda of understanding, correspondence or communications, including intra-company correspondence and communications, e-mail, texts, reports, notes and memoranda, summaries and recordings of conversations, meetings and conferences, summaries, minutes and records of telephone conversations, meetings and conferences, summaries and recordings of conversations, manuals, publications, calendars, diaries, technical and engineering reports, data sheets and notebooks, photographs, audio and video tapes and discs, models and mockups, expert and consultant reports, and drafts of originals with marginal comments or other markings that differentiate such copies from the original.

Data Requests Set 1

CPCNH 1-1. Referencing the Testimony of Douglas W. Foley, Robert S. Coates Jr., and Douglas P. Horton, dated June 11, 2024, at Bates page 01373, lines 10-13, please provide a copy of the "AMF Feasibility Assessment" developed by consultant West Monroe.

CPCNH 1-2. With regard to annual purchases of new meters for new customers and to replace meters taken out of service:

(a) How many new meters were purchased during the test year and what overall cost?
(b) Of those new meters purchased during the test year how many were purchased for the purpose of replacing existing meters that are taken out of service and how many were for new customer service?
(c) For the new meters purchased during the test year, please provide the model numbers and either Eversource specifications for each meter type purchased or the manufacturer's publicly available specification sheet for such meter types, including single phase, three phase, and hourly or sub-hourly interval meters.
(d) Please provide the purchase cost for each such meter type and the fully capitalized cost for each such meter type that includes any overhead and labor costs for installation that are typically capitalized.
(e) Are such meters added to rate base with depreciation commencing when purchased and placed into inventory, when installed, or otherwise?
(f) Are the cost of such new meters depreciated over 20 years?
(g) What was the inventory of purchased but uninstalled meters at the beginning and end of the test year, by meter type?
(h) Does the inventory of new meters at the beginning of the test year plus purchases of new meters during the test year less inventory at the end of the test year approximately equal the number of new and replacement meters installed during the test year? If not, why not?
(i) Were there any normalization of meter purchases or for installations of replacement or new services in the test year? If so, please describe.

(j) Are future annual meter purchases, by quantity and type, expected to be similar to the number purchased during the test year? If not please explain what such differences might be and how many new meters might be purchased over the next 5 years. Please provide a potential range of such purchases if there are no single point estimates.

CPCNH 1-3. Referencing the Company's response to COOK 1-006: it appears based on Eversource's data request responses to Mission 1-016 and LGC 2-010 in DE 19-197 that the Company's responses to COOK 1-006 are inconsistent with prior Company representations. In that context, please (a) confirm, modify, and/or update as necessary the Company's prior data request responses in DE 19-197, which are provided below, and (b) re-issue the Company's responses to COOK 1-006 to correct any prior inaccuracies or misrepresentations.

Mission 1-016 Request:
For Eversource only: Mission:data is aware of two types of automated meter reading ("AMR") meters. One broadcasts a single kilowatt-hour reading, frequently referred to as a "register read." The second broadcasts a load profile over some time period – for example, 15-minute usage data for the past 30-45 days. Both transmissions are picked up by a mobile receiver. With this description in mind, which type of AMR meter has Eversource deployed in New Hampshire? Please provide a description of AMR meter types and numbers deployed by customer class and whether and how load profile information is available.

Eversource Response to Mission 1-016:
Eversource NH has deployed two main types of AMR meters; those with traditional ERT modules that transmit one or more register values (depends on rate requirements and meter programming), or the Itron Bridge meter that is configured to operate in a manner similar to traditional AMR meters by transmitting one register reading (typically total kWh) and upon receiving a command from our drive-by meter reading system (FCS) possibly other register values such as maximum kW demand. None of the AMR meters provide interval data to the drive-by meter reading system. The Itron Bridge meters are capable of recording limited interval data, but Eversource NH is not able to collect and process that data via the drive-by meter reading system. Please see attachment MISSION 1-016 Attachment A, for a table of meter type codes vs. the customer categories (Residential, Commercial, Industrial) and how many meters are installed as of 9/2/2020.

LGC 2-010 Request:
Regarding EU response to request from Mission Data No. MISSION 1-016:
[excerpting the above data request and response omitted]

(a) Please provide how many Eversource's AMR meters are (1) broadcasting customer usage data on a regular basis via radio frequency and provide the transmission message frequency for data being broadcast by each meter, and (2) how many Eversource AMR meters broadcast upon receiving a command from FCS (drive-by).

(b) In both cases, please confirm whether customer usage data is broadcast unencrypted or encrypted, and if encrypted, please provide the encryption standard relied upon. Please provide the current installed count of different module types (e.g. R400 ERT, R300 ERT) by meter type (as specified in Attachment A).

(c) Please describe the register value and transmission capabilities of the different module types. Please provide any brochures and technical specifications for the different meter types and module types.

Eversource Response to LGC 2-010:

(a) All AMR meters broadcast some usage data regularly, typically in the 900MHz range. Meters with R300 type ERT modules broadcast every 2~3 seconds. Meters with R400 ERT modules, and Bridge meters, broadcast every 30 seconds or so. Bridge meters that transmit more than a single value (total kWh usage) will transmit the extra/ supplemental data values only after receiving an appropriate command from the FCS drive-by meter reading system.

(b) Meter readings transmitted to the meter reading system are not encrypted, but they do not contain any customer identifying information. Typically, the transmissions consist of the data value(s) and the device ID to know which meter it came from.

(c) Technical specifications and brochures are available to interested parties from the meter manufacturers, typically via their web site.

The older type AMR meters, such as an Itron Centron C1SR meter equipped with an R300 ERT module, were the most common ERT equipped meter used by Eversource prior to the AMR conversion project. They are considered to be "low power" ERT meters, relative to newer AMR product offerings. Here are the technical specifications, as confirmed by Itron's technical support personnel:

- *Transmission signal frequency range: 910 to 920 MHz (an unlicensed frequency band)*
- *Transmission pattern: Spread spectrum, frequency hopping (to minimize interference issues with other devices operating in this spectrum)*
- *Transmission power output: 0.75 mW (0.00075 watts)*
- *Transmission message frequency: 1 message, approximately once every 2 seconds*
- *Transmission message duration: 5.86 mS (0.00586 seconds)*

The "high power" (R400) version ERT in the Centron C1SR has essentially the same characteristics, except for the following parameters:

- *Transmission power output: 100 mW (0.1 watts)*
- *Transmission message frequency: 3 messages (same message sent 3 times in quick succession), approximately once every 30 seconds*

The Centron Bridge meter has similar specifications as the R400 module except with a power output of 283 mW.

CPCNH 1-4. Referencing the Company's response to COOK 1-006, and the clarifications provided above in CPCNH 1-3, please:

(a) Provide the current installed count of different module types (e.g. R400 ERT, R300 ERT) and meter type, binned by distribution rate class / code (e.g., R, R-OTOD).

(b) Confirm or provide clarifying responses to the following statements:

(i) Practically all of the Company's AMR meters in New Hampshire are currently broadcasting unencrypted usage data and device ID on a sub-minute basis.

(ii) Practically all of the Company's AMR meters in New Hampshire are capable of transmitting interval usage, demand, and other data on at least a daily basis; however, collection of such interval data would require deployment of a communications network.

(iii) The Company's current practice of collecting meter data once per month via a drive-by metering system precludes the collection of interval meter data from AMR meters.

(iv) In Massachusetts, the Company is (1) deploying an Advanced Metering Infrastructure (AMI) system in Massachusetts, inclusive of meter data management, customer information, and billing systems (MDMS, CIS/billing) capable of ingesting, validating, and processing interval meter data, and (2) will be providing individual customer and batch exports of AMI interval meter data to customers and Load Serving Entities on a daily basis through a certified implementation of Green Button Connect.

(v) The MDMS and CIS/billing systems being deployed in Massachusetts could be configured to also accommodate interval data sourced from meters in New Hampshire, to (1) obviate the need to continue maintaining the Large Power Billing System, and (2) accommodate at minimal additional cost interval data sourced from (a) 3rd party owned and operated interval meters, such as those that are anticipated to be installed by DER Aggregators acting as meter readers as required under ISO-NE's FERC Order 2222 compliance plan and associated tariff changes effective November 1, 2026, and/or (b) any AMR meters reporting interval data via a communications network, which could be initially deployed in the most urban / dense portions of the Company's territory (e.g., Nashua, Manchester) to enable interval data collection on behalf of a significant proportion of customers at least cost.

(c) Respond to the following questions:

 (i) Has the Company evaluated the feasibility and cost effectiveness of leveraging the MDMS and CIS/billing systems being deployed in Massachusetts to accommodate interval data sourced from meters in New Hampshire, or any other aspects of what is proposed in (v) above?

 (ii) Regarding the statement in Response to Cook 1-006 that "*AMI would also require the installation of a communication network, customer meter data management system and potential updates or changes to then prevailing billing systems as appropriate*" has the Company given any consideration to using existing cellular data networks to communicate with advanced meters through a subscription based meter data management system where most costs after integration can be charged on a per meter basis to allow for incremental implementation of advanced meter functionality?

CPCNH 1-5. Referencing the transcript of the PUC Hearing held on October 8, 2024, p. 142, line 21 to p. 145, line 21: the Company described its Volt Var Optimization (VVO) cost benefit analysis as being based on "*our experience in Massachusetts for a proxy of benefits, since we haven't done it yet in New Hampshire*" with quantified benefits of reduced energy losses and demand losses, reduced carbon emissions, and reduced costs of energy and transmission costs allocated to NH, resulting in a benefit cost ratio of 1.2 to 1.4, which was described as being equivalent to a net present value of $30-$40 million in benefits versus $22.5 million in costs.

(a) Please provide the VVO Cost/Benefit Analysis conducted for Massachusetts and any accompanying workbooks.

(b) Please provide any additional workbooks, calculations, reports, or other materials relied upon to adapt VVO benefit cost estimates from MA to NH.

(c) Please provide separate cost savings for energy, transmission, and any other categories used in the analysis, by month and year and in total.

CPCNH 1-6. Referencing the Company's response to DOE 4-068, which indicates that Eversource "*will supplement Attachment DOE 4-068(b) to provide a higher-level categorization of each project so that the specific projects are linked to the numerous aspects of PSNH operations*." Please provide the afore-referenced supplement.

CPCNH 1-7. Referencing Attachment DOE 4-068(b), line no. 231 and 232, asset description "Energy Supply – Load Settlement" (for both lines):

(a) Please clarify the reason(s) why lines 231 and 232 both list the asset description "Energy Supply – Load Settlement" but provide different costs and allocations to New Hampshire.

(b) Please confirm that asset description "Energy Supply – Load Settlement" refers to software that the Company purchased and customized to perform load profiling and settlement functions.

(c) Please confirm or clarify that the total cost for load settlement software allocated to New Hampshire is approximately $500,000, given the apparent amortization over 5 years.

(d) In what month and year did amortization of the load settlement software begin?

(e) What other test year or normalized annual operating costs are directly associated with load settlement services other than software amortization?

(f) Please confirm or clarify whether the software vendor was ABB, Inc.

(g) Please provide the contract executed between the Company and vendor governing the deployment and use of the software, and any updates thereof.

(h) Please provide all technical manuals and other documentation regarding the load profiling and settlement software in the Company's possession.

(i) Please summarize the load profiling and settlement software calculations including the sources and latency of all data required as inputs to the calculations.

(j) Please confirm that the software is not currently tracking hourly generation exported to the distribution grid by DERs counted as load reducers, whether distribution interconnected under 5 MW or behind-the-meter, and fully crediting Load Serving Entities for such exports adjusted by line losses by decreasing their hourly load settlements. Has the company estimated the cost that would be required to do so in compliance with RSA 362-A:9, II? If so, please provide the cost estimate and all supporting documentation. If not, why not?

(k) Please confirm that the Company has instead configured its billing system to convert all instances of net generation exports recorded by customer meters into a zero value prior to exporting the data to the load settlement software and describe how all such exports must therefore be allocated to Load Serving Entities in proportion to their profiled load in each hour by the load profiling and settlement software.

(l) Is the same software used to estimate and report peak hourly demand to ISO-NE for purposes of allocating generation capacity to customers and transmission costs to PSNH? If not, please provide comparable descriptions of the systems, data sources and latency, calculations, and processes relied upon by the Company for these purposes, and how exports to the distribution grid from DERs counted as load reducers are accounted for.

CPCNH 1-8. Does the Company meter the power flow onto the distribution grid at all of its bulk distribution substations? Is this data used for the purpose of informing load settlement, capacity and transmission peak hour calculations referenced above in CPCNH 1-7? Alternatively, does the Company rely on estimated rather than metered power flow for any bulk distribution substations in these calculations? If the latter, please (1) describe the estimation methodology employed, (2) provide the number of bulk distribution substations that are not metered on either the distribution or transmission side of the interconnection, and (3) clarify whether the Company is proposing in this plan to begin metering the power flow onto the distribution grid on some or all remaining bulk distribution substations.

CPCNH 1-9. With the following references to the transcript of the PUC hearing held on October 8, 2024:

- The Company represented that using DERs to provide grid services would require (#1) incorporating requirements into interconnection agreements to deploy onsite equipment enabling real-time monitoring communications and utility control of DERs, (#2) deploying a new Distributed Energy Resources Management System (DERMS) integrated with a Distribution Management System (DMS), and (#3) establishing an operating agreement for customers permitting utility control over the DERs for use as a grid asset in exchange for compensation. (p. 151, line 10 to p. 153 line 11.)
- The Company is not proposing to implement #1 and #3 above in this plan (p. 153 line 12 to 20) but is requesting approval to spend $8.5 million to deploy DERMS in New Hampshire; the Company has not performed a cost/benefit analysis quantifying the potential benefits of using DERs to provide grid services in NH but has indicated it will provide a written summary of prospective benefits, potentially accompanied by initial estimates. (p. 136, line 4 to p. 139, line 5.)
- The Company is in the process of implementing #1, #2, and #3 above in Massachusetts, with a target date of beginning to leverage DERs as grid resources in the latter part of 2027. (p. 154, line 1 to p. 156, line 4.)
- The Company has not deployed and has not planned for the deployment of a DERMS or DMS system in Connecticut. (p.155, line 8 to 12.)
- Regulators in Connecticut have ordered the deployment of a single Local Flexibility Market across regulated utility territories (Eversource and United Illuminating) operated by Piclo to enable the registration, contracting, dispatching, and settlement of approximately 35 MW of 3rd party owned and operated DERs to provide a variety of distribution grid support services. (p. 168, line 1 to p. 173, line 12.)

And with additional reference to:

- The Company's response to PUC TS1-005 (Corrected), TABLE PUC TS1-005, indicating the intent to install "*DER Gateway*" devices "*for the control and monitoring of DER*", with reference to the Company's Testimony, Bates p. 02167 (summarizing the Company's vision for DERMS).
- The Testimony of Freeman, Schilling, et al., Attachment: NH Distribution System Plan (DSP), Bates p. 02132, which explains "*For NWAs to be considered a reliable solution, the Company's framework, and industry best practice requires full operational control, and ideally, ownership of the NWA by the EDC.*"
- The Company's response to CLF 2-002, asserting that "*the Company requires ownership of the dispatch mechanism (e.g. DERMS)*" for BTM DERs and additionally "*requires ownership of FTM*" DERs to utilize such assets for NWA purposes.

- The Testimony of Freeman, Schilling, et al., Attachment: NH Distribution System Plan (DSP), Bates p. 02167-02168: where the Company characterizes FERC Order 2222 as "*establishing a path to the regional market for aggregated DERs which may compete with local distribution operating conditions*" and asserts, in reference to the Company's proposed DERMS, that such "*a system to manage the local, global, and contractual constraints that each DER potentially are subject to*" will be required as a consequence.

Please respond to the following requests:

(a) If available, please provide the written summary of prospective benefits for deploying a DERMS platform in New Hampshire, potentially accompanied by initial estimates of quantified benefits, as the Company committed to preparing for the Commission at the hearing held on October 8, 2024. If not yet available, please advise on when the Company anticipates being able to provide this document.

(b) Please provide the following information regarding the Piclo market platform in Connecticut:

(i) The timeline and summary of key milestones starting from the decision to deploy Piclo's market platform through the launch of auctions for grid support services, and the anticipated start date for said grid support services.

(ii) The contract and/or service agreements between Piclo and the Company, and any additional documentation that would provide useful context.

(iii) The number of "Flexibility Service Providers" (FSPs) and the quantity, technology type, and capacity of DER assets registered on the platform to date.

(iv) A status update regarding the solicitations for grid support services that recently concluded, including a table showing the need (e.g., infrastructure deferrals, capacity support, emergency reliability, etc.), type of grid service requested, target DER capacity, auction budget, and whether and the extent to which sufficient DER capacity was contracted to meet the Company's needs.

(v) The cost of deploying and operating Piclo's platform, separately accounting for the Company's internal costs (e.g., platform integrations, associated support services, etc.) from any payments to Piclo for licensing, fees, etc., and to the FSPs / DERs for provision of grid services.

(c) Please explain how 3rd party owned and operated DERs will soon be providing a variety of distribution grid support services in Connecticut, contracted for and dispatched through the Piclo platform, even though the Company has not deployed and is not planning on deploying the DMS and DERMS functionality that the Company has represented as being necessary to do so in New Hampshire and Massachusetts?

(d) Please additionally clarify whether the Company has, in Connecticut, incorporated requirements into interconnection agreements to deploy onsite equipment enabling real-time monitoring communications and utility control of DERs, installed DER Gateway devices on customer premises to do so, and established an operating agreement for customers permitting utility control over the DERs for use as a grid asset in exchange for compensation – as the Company also represented were necessary steps prior to sourcing grid services from DERs – or whether these requirements have alternatively been met, provided in other ways, or otherwise been obviated by Piclo's services.

(e) In the United Kingdom, where Piclo is based and appears to be well established as a flexibility market platform provider to multiple distribution utilities:
   (i) A significant number of 3rd party owned and operated FTM DERs (primarily storage) are providing grid support services. Given this context, would the Company consider revising its representations that "industry best practice" requires only relying on utility-owned FTM DERs to provide grid services?
   (ii) Piclo appears to be also facilitating coordination and integration with wholesale electricity markets. Would the Company agree that deploying a single platform to facilitate provision of DER services to utilities in New Hampshire, and to coordinate with and enable integrations of DERs into ISO-NE, is likely to be more cost effective than relying on four different distribution utilities to separately do so? Why or why not?

CPCNH 1-10. With Reference to the Company's response to LCC 1-007:

(a) Please confirm that:
   (i) The Massachusetts Department of Public Utilities (MA DPU) has found that "pri*cing 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*", 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 servic*e", and consequently directed the Company "*to evaluate further the expansion of coincident peak transmission billing to NSTAR Electric customers*." (MA DPU Docket No. 17-05, Order DPU 17-05-B, January 5, 2018, at pp. 211-213.)
   (ii) The Extra Large class T-5 customers in the Company's Western Massachusetts territory have been charged for transmission based on their individual metered demand at the time of the monthly transmission system peak hour since 1997, and more recently, coincident peak transmission billing was extended on an opt-in basis to Large General Service Rate G-3 customers across both the Company's Western Massachusetts territory and Eastern Massachusetts territory (comprised of the Cambridge Service Area, Greater Boston Service Area, and South Shore, Cape Code & Martha's Vineyard Service Area).

(b) Please confirm that all Class T-5 customers, and Rate G-3 customers in Massachusetts which have elected to be charged for transmission based on their individual metered demand at the time of the monthly transmission system peak hour, are able to lower their transmission charges by using BTM DER generation or storage assets to decrease their usage during the monthly peak hour.

(c) Please clarify the Company's treatment of BTM DER exports to the grid from such customers during these hours, e.g., are net exports compensated at the same rate, or are the benefits socialized, and if so, how?
(d) Please clarify whether the Company is or is not planning to expand default or opt-in pricing of transmission based on customer coincident demand to other rate classes in Massachusetts.
(e) Please clarify whether the Company is planning to propose enabling interval metered customers in New Hampshire to be charged for transmission based on their individual metered coincident demand during the monthly peak hour. If not, would the Company support doing so? Why or why not?

Sincerely,

Clifton Below

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Before the New Hampshire Public Utilities Commission

DE 24-070
Public Service Company of New Hampshire d/b/a Eversource Energy

Request for Change in Distribution Rates

Community Power Coalition of New Hampshire Technical Session Data Requests Set TS-1 for Following Technical Session Held December 11, 2024

December 17, 2024

Technical Session Data Requests – Set TS-1

CPCNH TS 1-1. RE: CPCNH 1-002(d) During the December 11, 2024 Technical Session, Mr. Below asked Mr. Christopher M. Kellogg to explain why the Bridge AMR meter's CFI is less per meter than for the legacy AMR meter, while the Bridge AMR meter is more expensive than legacy AMR meter. Mr. Kellogg indicated that he would have to get back to us. Please provide an explanation for this question.

CPCNH TS 1-2. Re: CPCNH 1-002: Please provide specification sheets for the Centron Bridge R-400, Aclara I210 ERT, and Aclara Cellular KV2C meters.

CPCNH TS 1-3. Re: CPCNH 1-002: Referencing Attachment CPCNH 1-002(b), the technical specifications for Centron Bridge meters states that "The new CENTRON Bridge also manages and collects up to 40 days of 15 minute interval data from two channels, which enables a range of capabilities." Related, the specification states "Two channels of 15-minute interval data with 40 days of data retention; intervals can be retrieved as 15 minute, hourly, daily or single historical read" under the heading "ChoiceConnect Mobile Mode".

(a) Please confirm whether the Centron Bridge meters are capable of recording 40 days' worth of interval data.
(b) If the Centron Bridge meters are not capable of recording 40 days' worth of interval data, please verify the length of storage capability.
(c) Please clarify whether such interval recordings are able to be retrieved via a mobile collection system (e.g., drive-by meter reading), and discuss what specific efforts would be required to enable this for PSNH.
(d) Please explain the meter reprogramming process that would be required to enable interval data recording for Centron Bridge meters. Regarding the suggestion made at the workshop that doing so would require "pulling" each meter, please clarify whether

Centron Bridge meters are capable of being reprogrammed in place, ‘over the air’, such as by using a handheld reprogramming device.

CPCNH TS 1-4. Re: CPCNH 1-002: During the December 11, 2024 Technical Session, Mr. Golding asked how the interval data from the cellular meters that Mr. Kellogg explained are used for load research and some larger C&I customers is ingested, processed, stored, and used. . Ms. Dawn Coskren explained that the data goes into the MV90 system. When Mr. Golding asked her to explain how the MV90 system worked, Ms. Coskren indicated that she was “not part of that group” but said she could provide us with more information. Please provide a detailed explanation of how the MV90 system and related systems ingest and make use of the interval data from the cellular meters and any other interval meters. Please include a detailed description of the process, cadence, reliability and extent of interval data transmittal between cellular interval meters and the MV-90 system, which systems are relied upon for the subsequent Validation, Editing, and Estimation (VEE) processing of interval data, which systems store the interval data, the transmission methods that are allowed/utilized to provide access to the interval data, and whether third parties are currently accessing or receiving interval data. For example:

(a) How are cellular interval meters configured, including in terms of the interval of recording, data points collected, and number of interval reads stored on the meter?
(b) What is the time delay between electricity consumption at a customer premise and transmission of raw interval usage data?
(c) What percentage of cellular interval meters are read and are processed through the MV-90 and by when each day?
(d) By what time is the raw meter data processed and validated each day?
(e) What is the incidence and magnitude of exceptions and errors that require further resolution and impose delays for a subset of interval meter data (and by when is that subset of meter data validated)?
(f) Where is the data system is housed (e.g., on premise, on premise at any third party, private cloud instance, public cloud instance, etc.)?
(g) What amount of historical data stored?
(h) Is a mirror in place for the system and at what cadence is that mirror updated?
(i) Is there is a historical data warehouse, and if so, what amount of history is stored there?
(j) What parties are given access to these systems?
(k) What data transmission methods are allowed/utilized (REST, batch export, etc.)?
(l) Is the system capable of transmitting interval data to third parties directly, or is it necessary to transmit the data to an intermediate location, such as a data warehouse?
(m) Which third parties are receiving the interval data, and for what purpose?

CPCNH TS 1-5. Re: CPCNH 1-002: Please provide a current count of installed cellular interval meters relied upon for load research and the construction of load profiles for settlements for different rate groups. Please provide a detailed description of the process and frequency of load profile construction for use in settlements.

CPCNH TS 1-6. RE: CPCNH 1-004(b)(v): Regarding each of Eversource's utility companies currently maintaining separate billing systems:

(a) Please confirm and expand upon the discussion indicating that Eversource intends to standardize AMI and related systems (e.g., ADMS, MDMS, billing/CIS, etc.) across its utility territories, including for PSNH eventually, so as to enable more efficient operations across the enterprise. As indicated during the workshop, please confirm that Centron Bridge meters are unlikely to be compatible with Eversource's AMI system and discuss the reasons why.

(b) Referencing Attachment DOE 4-068(b), line no. 89, asset description "Transmission Billing System", is this an Enterprise level system relied upon for billing purposes by PSNH? If so, please include a detailed description of this system. Please identify any other systems at the Enterprise level relied upon for billing purposes by PSNH.

CPCNH TS 1-7: RE: CPCNH 1-005 and the workshop discussion regarding clarification of how PSNH is estimating the value of avoided transmission cost savings to support investment in Volt-Var Optimization, please provide Attachments CPCNH 1-005(a) and (b) in Excel workbook format, including all formulae and links intact.

CPCNH TS 1-8.

(a) **RE: CPCNH 1-007(e):** Regarding the approximately $200,000 in annual support costs for load settlement services, please clarify whether is fully allocated to PSNH and briefly describe the nature of these support services (e.g., staff costs, ongoing vendor support costs, etc.)

(b) **RE: CPCNH 1-007(g):** Please provide an NDA for CPCNH's review and execution to permit access to the confidential materials requested. Please clarify whether PSNH is still in a contractual relationship with ABB for the load settlement software.

(c) **RE: CPCNH 1-007(g) through (l):** PSNH objected to responding to these data requests, regarding load settlement software and services, as not germane to the proposal in this docket. At the workshop, Eversource counsel requested that CPCNH respond in writing to clarify the relevance of the requests. CPCNH again requests that PSNH respond in full to CPCNH 1-007, and provides the following context justifying the data request:

- PSNH has identified the load settlement software at issue here as one of the Enterprise IT systems for which cost recovery is being requested in the proposal in this docket (*See* Attachment DOE 4-068(b), line no. 231 and 232, asset description "Energy Supply – Load Settlement.") Cost recovery is being sought for approximately $500,000 in software expense allocated to PSNH, along with $200,000 annually in ongoing related support services (*See* Responses to CPCNH 1-007 (a) through (f).)
- PSNH has characterized such Enterprise IT systems as being implemented to "…attain economies of scale, and achieve operational efficiencies and implement system-wide best practices more easily than if these projects were undertaken separately by each operating

company" and represented that Eversource "reviews each project on its own merits… when determining whether the operating companies would benefit from a shared service implementation or whether that project would be better suited to be implemented by the operating company. " (*See* Response to DOE 4-068(a).)

- At the workshop, PSNH representatives indicated that the proposal does not provide for any enhancements to the load settlement software and service capabilities; CPCNH expressed concerns that PSNH's load settlement software and related systems (e.g., billing systems) are not configured to satisfy New Hampshire statutory obligations, specifically to net DER excess generation from supplier load settlement obligations pursuant to RSA 362:A-9, II, or ISO-NE tariff obligations related to implementing FERC Order 2222, effective November 1, 2026, necessary to enable DER wholesale market access (specifically by enabling non-utility entities to install interval meters and act as the Assigned Meter Reader for DERs, and will require PSNH to receive such data for netting or reconstitution of load assets to avoid double-counting DERs as both load reducers and wholesale resources); CPCNH also expressed concerns that the ongoing inability of PSNH's load settlement software and related systems to accurately estimate and allocate DER impacts, both in terms of onsite net load profiles and exports to the distribution grid, and given the rapid and continuing growth in DER penetration, was undermining the statistical accuracy of PSNH's load settlements generally.
- CPCNH has previously detailed these and other related concerns regarding PSNH's load settlement software and services, and recommended modifications to load estimation and settlement practices. (*See, e.g.*, DE 23-063, CPCNH's joint *Motion for a Supplemental Order of Notice, Testimony, and Pre-Hearing Conference, and to Grant Additional Temporary Waivers to Eversource, Unitil, and Liberty Utilities* and *Joint Intervenors Reply Brief.*)
- In this docket, CPCNH has previously indicated that evaluation of PSNH's load settlement capabilities would be one an area of focus, in the following relevant context:

  > "As a joint power agency supplying default energy service, CPCNH has a broad interest in how PBR metrics may or may not incentivize appropriate IT system investments that either support or limit a competitive market for electricity supply and related energy services, considering our dependence on Eversource IT systems for meter data, Electronic Data Interchange (EDI), consolidated billing, and **<u>load settlement services</u>**, where such investments can also impact distribution and supply rates and costs to our Members and mutual customers." (*See Reply Brief of the Community Power Coalition of New Hampshire Objecting to Eversource Energy Motion to Limit Intervention*, CPCNH explained, at p. 11, emphasis added):

- Through CPCNH 1-007(g) through (l),and the related data requests provided here following on the workshop discussion, CPCNH is seeking facts relating to the evaluation of whether Eversource's choice of load settlement software was prudent, and the extent to which PSNH is or may be incentivized to invest in upgrading its load settlement capabilities and other IT systems necessary to support the competitive retail electricity market.

(d) **RE: CPCNH 1-007:** It is CPCNH's understanding that ISO-NE tariff obligations related to implementing FERC Order 2222, effective November 1, 2026, which are necessary to enable DER wholesale market access, specifically by enabling non-utility entities to install interval meters and act as the Assigned Meter Reader for DERs for settlement reporting purposes, will require PSNH to receive such data for netting or reconstitution of load assets to avoid double-counting DERs as both load reducers and wholesale resources). However, during the workshop, PSNH indicated that such requirements are still "in flux". Please clarify this assertion by explaining PSNH's understanding of what compliance with FERC Order 2222 will require regarding known or potential changes to metering and load settlement software and services, and identify which requirements are still "in flux".

(e) **RE: CPCNH 1-007:** Please confirm that PSNH is not requesting any funding in this application for enhancements to load settlement software. Please also explain how and on what timeline PSNH intends to implement metering and load settlement changes necessary to comply with FERC Order 2222 and related ISO-NE compliance plan requirements by November 1, 2026, and why any investments necessary to do so have not been included in the proposal at this time.

(f) **RE: CPCNH 1-007:** Please provide the initial and final hourly Unaccounted for Energy (UFE) and daily Capacity UFE values applied to produce load resettlements submitted to ISO-NE, which CPCNH understands are initially submitted daily and finally submitted 4 months after the trading day, from January 1, 2015 through the most recent date in 2024 that such data is available.

(g) **RE: CPCNH 1-007:** Please provide PSNH's estimation of behind the meter consumption (DER generation) as avoided sales, as shown in Docket No. DE 24-035, Attachments of S. Anderson, beginning on Bates page 134, in Excel workbook format, including all formulae and links intact, and any accompanying workpapers or explanations of such calculations.

CPCNH TS 1-9. Please confirm that Eversource has metering at all point of interconnection and is able to measure line losses at points of interconnection below RNS.

CPCNH TS 1-10. RE: CPCNH 1-009 (b), (d) and (e): PSNH objected to responding to these data requests, regarding the use of the Piclo Flex market platform to enable cost-effective grid services from DERs, as not germane to the proposal in this docket. At the workshop, Eversource counsel requested that CPCNH respond in writing to clarify the relevance of the requests. CPCNH again requests that PSNH respond in full to CPCNH 1-009, and provides the following context justifying the data request:

- PSNH is proposing to invest $8.5 million on a DERMS platform to facilitate management of DERs to provide grid services in this proposal in this docket and has not conducted a formal cost/benefit analysis to support the investment decision.
- At the October 8, 2024 hearing, responding to questions from Chairman Goldner and Commissioner Chattopadhyay on this topic, PSNH characterized the DERMS as "a foundational investment enabling the use of customer-owned assets as grid resources" and indicated that the prudency of deploying a DERMS depended upon being able to source grid services from sufficient numbers of DERs; subsequently, responding to Consumer Advocate Don Kreis on this subject, and the status of Eversource's Piclo Flex platform deployment in Connecticut, PSNH stated that "Combined with the DERMS, a Piclo program can be a good way to try and get the lowest cost resource by having folks bid to compete to provide the services that we need" and indicted an intent to explore deployment in New Hampshire "if it's successful in Connecticut…". (*See* Transcript of hearing held 10/08/24, at Bates 137-138, 155-157, and 172-173.)
- Through CPCNH 1-009(b), (d) and (e), CPCNH is seeking facts relating to the evaluation of PSNH's proposed DERMS investment:
    - CPCNH 1-009 (b) requests information relevant to understanding the deployment timeline, cost, and initial performance of the Piclo market platform in Connecticut. PSNH objected that "The details of the Piclo deployment are not relevant to the Company's proposal in this docket." CPCNH seeks this information to understand whether, on what timeline, and at what cost, it is reasonable to anticipate a comparable platform being deployed in New Hampshire, for the purpose of streamlining and expediting sourcing of grid services from DERs to a degree sufficient to support PSNH's $8.5 million DERMS investment proposal.
    - CPCNH 1-009(d) requests clarification of whether Eversource has already implemented the specific measures in Connecticut that it represented in this docket as being necessary to enabling grid services from DERs but which were not included in this proposal (in addition to DERMS: modifications to interconnection agreements, installation of DER Gateway devices on customer premises, and operating agreements to enable utility monitoring and control of DERs), or whether such requirements have been "met, provided in other ways, or otherwise been obviated by Piclo's services". PSNH objected that Connecticut interconnection agreements are not relevant to the Company's proposal in this docket." CPCNH observes that the question included but was not limited to interconnection agreements, and seeks this information to help evaluate PSNH's assertions of what is necessary to begin sourcing grid services from DERs, and whether more streamlined means of satisfying such requirements have been implemented in Connecticut that could be considered in New Hampshire to expedite use of the proposed DERMS platform.

- CPCNH 1-009(e) requests clarification regarding PSNH's assertion that FTM DERs would need to be utility owned and controlled to provide grid services, given that the Piclo Flex platform sources such grid services from 3rd party DERs for distribution utilities in the United Kingdom. PSNH objected that this "appears to be irrelevant to the Company's proposal in this docket." CPCNH seeks this clarification to better understand the potential benefits of the proposed DERMS deployment, specifically by enabling reliance on non-utility owned FTM DERs.
- CPCNH 1-009(i) requests clarification regarding whether deployment of the Piclo Flex market platform across all utilities in New Hampshire could support DER integration and coordination with ISO-NE market more cost effectively than "relying on four different distribution utilities to separately do so", in part because Piclo appears to be already beginning to do so in the United Kingdom. PSNH objected on the basis of asserting that "wholesale markets are outside the scope of this proceeding and a matter of federal jurisdiction." During the workshop, however, PSNH representatives stated that the proposal in this docket included proposed investments in what was characterized as "control room enhancements" to ensure that ISO-NE's dispatch of DERs aggregated for participation in wholesale markets was supportable by the PSNH's distribution grid. CPCNH observes that this topic is clearly in-scope.

CPCNH TS 1-11. RE: CPCNH 1-009: PSNH representatives stated that the proposal in this docket included proposed investments in what was characterized as "control room enhancements" to ensure that ISO-NE's dispatch of DERs aggregated for participation in wholesale markets was supportable. Please describe the proposed investments, functional requirements intended to be enabled regarding ISO-NE wholesale market coordination, any related enabling investments included in the plan, and the cost. Please provide citations to relevant parts of the proposal in the response for additional reference.

Sincerely,

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