THE STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISISON

DE 23-039

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

Request for Change in Distribution Rates

Community Power Coalition of New Hampshire

Testimony of Clifton C. Below

December 13, 2023

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I. Introduction and Qualifications

Q. Please state your name, business address and position relative to this docket.

A. My name is Clifton C. Below, and my personal office address is 1 Court Street, Suite 300, Lebanon, NH 03766. I am Chair of and appearing on behalf of the Community Power Coalition of New Hampshire ("CPCNH" or the "Coalition''), which was granted intervenor status in this docket. The Coalition is a governmental instrumentality of our 48 municipal and one county members operating as a joint powers agency to start-up and operate community power aggregations (CPAs). Five of our member municipalities with operating CPAs are served by Liberty Utilities for part of or all of their community: the City of Lebanon and Towns of Hanover, Enfield, Plainfield, and Walpole. We are now the electricity supplier for about 13,000 Liberty distribution service customers, nearly 30% of their total of ~45,000 distribution service customers. We serve customers in all or virtually all of Liberty's various rate classes, from D to G-1.

Q. Have you previously testified before this Commission?

A. Yes, in numerous cases. Relevant here, on behalf of the City of Lebanon, I provided testimony in DE 17-189, concerning Liberty's battery storage pilot (Exh. 12).[1] In that docket, I helped design the Time-of-Use (TOU) rates adopted and co-authored the "Technical Statement Regarding Time-of-Use (TOU) Model. (Exh. 20).[2] I also provided testimony on behalf of the City of Lebanon in DE 19-064, Liberty's last distribution rate case (Exhibits 27 and 28), and in DE 19-197, concerning development of a Statewide Energy Data Platform.

[1] https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189.html Found at Tab 33.
[2] https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_GSEC_TECH_STATEMENT_TOU.PDF.

Q. Please describe your relevant experience and expertise regarding electric utilities.

A. A detailed background statement can be found as Attachment 1 to my testimony in DE 22-060 concerning net metering tariffs[3]. I will only highlight a few keys elements of my background here. During my tenure as a State Representative from 1992-1998 I served on the House Science, Technology, and Energy Committee where I was heavily involved in energy and regulatory legislation. As Chair of the Policy Principles, Social and Environmental Issues Subcommittee of the Retail Wheeling and Restructuring Study Committee in 1995, I facilitated a consensus building legislative and stakeholder process that resulted in recommended "Restructuring Policy Principles" that became the core of NH's Electric Utility Restructuring statute, RSA 374-F, which was enacted to restructure and guide the future regulation of electric utilities in NH. In 1998, I was elected to the NH Senate, serving on the energy and utility policy committees throughout my six-year tenure. From 1997-2004, I served on the Advisory Council on Energy of the National Conference of State Legislatures (NCSL), including three years as Chair, which advised NCSL staff on emerging energy issues. I also served on the Energy & Electric Utilities Committee, Assembly on Federal Issues of NCSL where, as Chair in 2000-2001, I facilitated a consensus based comprehensive update of NCSL's National Energy Policy. I testified on behalf of NCSL before the United States Senate Committee on Energy and Natural Resources on "Electric Industry Restructuring," focusing on transmission and jurisdictional issues. I also served as a member of the National Council on Electricity Policy Steering Committee from 2001-2004, which was a policy collaborative with the

[3] Found under Tab 63 in the docket for DE 22-060: https://www.puc.nh.gov/Regulatory/Docketbk/2022/22-060/TESTIMONY/22-060_2023-12-06_CPCNH_ATT-TESTIMONY-BELOW.PDF

National Association of Regulatory Utility Commissioners (NARUC), the National Governors Association (NGA), and the National Association of State Energy Officials (NASEO).

In late 2005 I was appointed to serve as a NHPUC Commissioner with my tenure ending in February 2012. During that time, I served on the Federal Energy Regulatory Commission (FERC)-NARUC Smart Grid and Demand Response Collaborative, 2008-2011, and on the Electric Power Research Institute (EPRI) Advisory Council, 2009-2011 and its Energy Efficiency/Smart Grid Public Advisory Group, 2008-2010. Through my involvement in NCSL, NARUC, New England Conference of Public Utilities Commissioners (NECPUC), ISO New England stakeholder processes and particularly with EPRI, I was fortunate to develop subject matter expertise into many emerging issues in the electric utility industry at the intersection of technology, science, policy, markets, and regulation, including grid modernization, smart rates, market design, energy efficient technologies, and distributed energy resource issues (DER).

II. Overview of the Coalition's Position and Proposed Conditions

Q. Would you summarize your testimony?

A. Yes. My testimony focuses on five issues: 1) rate modernization, including TOU rate issues; 2) battery storage; 3) advanced metering infrastructure (AMI); 4) performance-based ratemaking (PBR); and 5) the proposed Electric Reconciliation Adjustment Mechanism (ERAM). Each will be addressed in more detail below, but I will briefly summarize the key points.

1. **<u>Rate Modernization</u>**: We are generally supportive of Liberty's rate modernization strategy and applaud the roll-out of the proposed whole-house residential and small commercial TOU rates. However, the strategy falls short in two critical respects:
   - For the largest customer class, G-1, where hourly interval meters are already in place and used for load settlement along with customer-specific capacity tags that are based customer specific share of the annual hour a coincident peak demand on the overall ISO-NE system, there is no movement toward distribution demand charges being based on share of coincident peak demand rather than an individual maximum demand rachet, regardless of when that demand occurs relative to the available capacity of the distribution system. To address this shortcoming, CPCNH recommends that the Commission direct Liberty take whatever revenue requirement is approved for G-1 customers and work to redesign demand charges, so they are based on share of coincident peak or TOU periods.
   - Liberty is preparing to offer TOU rate options for energy supply, along with distribution and transmission components, to its default energy service customers without the ability for CPAs & Competitive Electric Power Suppliers (CEPS) to offer supply service at TOU rates using the same TOU time periods, which is contrary to its own tariff and NH EDI standards. To address this shortcoming, CPCNH recommends that the Commission condition the roll-out of new TOU rate options on the ability of Liberty to simultaneously fully enable CPAs and CEPS to provide TOU energy service supply rates through use of the EDI system and consolidated billing, including for net metered customer-generators. The performance incentive mechanism (PIM) related to TOU rate adoption should not

be available or applicable until Liberty has fully enabled CPAs and CEPS to offer TOU energy supply rates through Liberty consolidated billing, including credits for NEM customer-generators that export to the grid based on TOU supply rates and the corresponding load settlement changes necessary to properly credit CPA and CEPS load assets for NEM exports to the grid as a load reduction relative to the ISO-NE load obligation pursuant to RSA 362-A:9, II.

2. **Battery Storage:** CPCNH supports implementation of a bring-your-own-device (BYOD) battery storage program along the lines proposed by Liberty but disagrees that the program should be limited to no more than 150 participants over the next three years.

3. **Advanced Metering Infrastructure (AMI):** CPCNH generally supports Liberty's planned implementation of AMI with the caveat that Liberty should engage CPAs, CEPS, and other potential users of granular interval data early in the process to take their needs for meter data access into full consideration in specifying functionality and billing options that are enabled. Below, I offer some examples of specific considerations that Liberty should utilize to plan for and help "future proof" AMI roll-out.

4. **Performance-Based Ratemaking (PBR):** CPCNH is generally supportive of the idea of PBR as proposed by Liberty, but is concerned that the basic metrics may be too limited; set too low of a threshold for acceptable performance; and are lacking in an appropriate metric that reflects how well Liberty is doing **to enable** CPAs and CEPS the ability to offer all rate options that Liberty offers as well as further enabling and supporting third party deployment of distributed energy resources (DERs), including innovative demand response programs. One metric that might be used in this regard is whether Liberty's customer base, both those on utility default service and those on competitive supply,

including CPAs, are improving their load factors compared to recent history or the rest of New Hampshire and New England as a whole.

5. **<u>Electric Reconciliation Adjustment Mechanism (ERAM):</u>** Generally CPCNH has no objection to the proposed ERAM, except that we disagree with shifting all net metering (NM) costs from the energy service rate to the proposed ERAM recovered from all customers until certain issues are resolved concerning load settlement and future NM rates being determined in DE 22-060.

III. Rate Modernization

Q. What is your view on Liberty's Rate Modernization Strategy?

A. We are generally supportive and concur with the direct testimony of Greg Tillman (at p. 5) where he states:

> "rate modernization includes the process of establishing rates that (1) create strong connections to the underlying costs of providing electric service; (2) incentivize 14 efficient customer behavior; and (3) provide customers with a choice in pricing products."

We also concur with Liberty's belief that "it is critical to connect the price signals more directly to the underlying costs of providing service" and find that this is consistent with RSA 374-F:1, II that calls for the development of competitive markets for electricity as part of electric utility restructuring that "provide electricity buyers and sellers with appropriate price signals."

In DE 19-197, Liberty's last rate case, in my testimony on behalf of the City of Lebanon, which I also represent in this case as a member of CPCNH, I urged the Commission:

> "to encourage Liberty to develop and propose similar opt-in TOU rates [to those proposed for residential EV charging and used in the battery pilot] for its non-resident customers, starting with the G-3 rate class, as that could use the same basic model structure and much of the same data as for residential customers, and then for G-2 and G-3 rate classes with demand charges more based on share of coincident peaks. … This

> would be a big step forward towards providing more appropriate and economically efficient cost causation-based price signals to customers as contemplated by RSA 374-F and grid modernization."

While I am encouraged to see that Liberty followed up on that suggestion in proposing a three-part, whole house TOU rate as well as TOU rates for the G-3 rate class, I am disappointed that no such change is proposed for the G-1 class. This is especially the case because the G-1 class already has interval metering which can support a more advanced TOU rate structure compared with the legacy two-period TOU structure inherited from National Grid that broadly defines on-peak broadly as 8 am to 9 pm on weekdays. I understand that AMI metering is needed for broadly modernizing the G-2 rates, but it seems that there is an opportunity to shift demand charges for G-1 customers to closer alignment with coincident peak demands and perhaps implement either a TOU transmission charge or shift that charge to a coincident peak based demand charge instead of a flat per kWh charge, which does not reflect the underlying cost causation. G-1 customers have some of the greatest ability to shift loads off coincident peaks (or relatively narrow TOU peak periods) and more motivation than most other customers due to their ability to minimize their individual capacity tags and future costs when they are on competitive supply that takes that cost driver into account for customized rates.

Q. Why is it important to base demand charges primarily on coincident peak demand?

A, The capacity of the entire electric system, generation, transmission, and distribution must be designed to meet coincident peak demands on the system, with a safety margin. Although, like transmission, distribution system costs are relatively sunk and fixed based on the invested capital in physical facilities, charging rates based on share of coincident peak demand provides a strong marginal cost price signal as to the fact that investment in new increments of capacity will be triggered to a substantial degree by growth in the overall peak demand on each component within the system. Hence, under federal rate regulation, the revenue requirement for embedded costs in transmission are based on share of monthly hour of coincident peak demand, while the forward capacity market for generation is based on the single hour of greatest annual demand on the ISO-NE system. It is also important to note that, generally, a new increment of transmission or distribution system capacity will tend to cost more than the average cost of comparable existing capacity, so will tend to raise the average cost per kWh as more capacity is added, unless the peak grows slower than overall consumption. This is due to both the amortization of historic investments and rising costs of new equipment and construction.

Enabling G-1 and other customers to shift load off coincident peaks and into periods of lower demand through appropriate price signals, will tend to result in improving load factors or asset utilization rates, meaning that all those fixed capacity costs will be spread over more kWh, rather than fewer kWh when peak demand grows faster than overall consumption. Also certain electrical equipment, such as transformers, tend to age and degrade faster when they are heavily loaded (and generate higher internal temperatures from more resistance) than when they are more lightly loaded on average and at peaks.

Q. What do you recommend going forward?

A. Principally, I recommend that Liberty be directed to propose modernized G-1 rates along the lines discussed for consideration by the Commission sooner than later. This may not be feasible on the same timeline as implementing a TOU option for G-3 or D but should not wait another three years. Bringing forth a proposal within a year of a final order in this case for implementation in the 2nd year of the multi-year rate plan may be reasonable.

Q. Having helped Liberty design their original three-part TOU rate, what do you think of the consolidated TOU rate model?

A. I support Liberty's proposal. The original model was overly complex and somewhat difficult to use and maintain because it evolved rapidly and numerous switches and options in it to test a variety of options and scenarios. Also, the portion originally developed by Lon Huber was subject to a non-disclosure agreement as intellectual property, so it was less than fully transparent. The consolidated model appears to be based on substantially the same cost causation principles, producing similar results, and is cleaner for these specific applications.

Q. What is CPCNH's concern with being able to serve TOU customers?

A. In his direct testimony Mr. Tillman (at p. 25) stated that:

> customers who elect to be served under Rate D-TOU or G-3-TOU may elect an alternative energy service provider. It should be noted that customers who choose a competitive supplier must seek access to time-differentiated energy service rates through their selected energy service provider.

We followed up on this with data request CPCNH 1-1 asking:

> If Liberty's EDI and consolidated billing system will support Competitive Electric Power Suppliers (CEPS) and Community Power Aggregations (CPA) TOU rate options for energy service using the same 3-part TOU rate periods as defined in Liberty tariffs and as provided for in NH EDI standards, for all TOU rate offerings by Liberty?

The initial response was:

> Liberty's EDI and consolidated billing system will continue to support CEPS and CPA as defined in Liberty tariffs and provided for in NH EDI standards for all TOU rate offerings by Liberty.

In technical session we sought further clarification since the response seemed to imply that CPAs would be able to get TOU usage data through EDI and provide TOU energy service rates that very by the utility TOU periods for use in rate-ready consolidated billing. On 12/6/23, Liberty supplemented their response, which is attached as Attachment 1 to my testimony.

In the supplemental response Liberty asserts:

> Liberty does, and will continue to, transmit EDI files for all existing customers enrolled in Liberty's TOU rate offerings and served through an alternative energy provider. Liberty's billing EDI files are formatted in compliance with the agreed upon use of existing 810 EDI standards discussed during the Massachusetts EBT Working group and is in accordance with NH rules, and statutes, and company tariff where TOU demand is sent and not TOU period energy consumption for its 3-period and 2-period TOU rates.

Here, Liberty notes that its EDI files are in compliance with Massachusetts EBT working group agreed upon 810 EDI standards, but also asserts that they are in accordance with NH rules and the company tariff. CPCNH respectfully disagrees. Liberty's own tariff states that electronic business transactions and data exchange with competitive suppliers will be in accordance with "the rules and procedures set forth in the EDI Working Group Report."[4] The EDI Working Group Report is a defined term meaning "The report submitted by the Electronic Data Interchange Working Group to the Commission on April 2, 1998, and approved by Order 22,919."[5]

Our considered opinion is that the EDI Working Group Report, considered in its entirety, expressed both the intent and the technical requirements to enable competitive suppliers to be able to offer any rates that a utility's billing system is capable of offering for their own electricity supply customers and included all the technical provisions for reporting and exchanging TOU usage data and billing rate fields. An index to the documents that comprise the EDI Working Group Report and PUC Order No. 22,919, with hyperlinks, is provided as Attachment 2.

The main consensus report (EDIREV53) in the discussion on "Usage and Billing" provided that competitive suppliers would provide the utility "with its price schedule for the

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[4] Liberty NHPUC Tariff No. 21, Section 62, iii, 1(n), original page 79, for example.

[5] Tariff at Section 62, ii, original page 77.

relevant Customer or customer class" (at 19) for use in Consolidated Billing Service and further stated:

> Competitive Suppliers who select the Consolidated Billing Option are limited to the rate structures, customer class definitions and availability requirements that are within the capabilities of the Distribution Company's billing system.

The utility may argue that while its billing system is capable of billing different energy service rates by TOU period for customers in a TOU rate class for its own default service customers, it may not be capable of doing so for competitive suppliers. However, such an interpretation would fly in the face of the context in which that statement was made. At the time the Commission approved this report and called for its implementation none of the utility billing systems supported competitive suppliers use of their billing system. The EDI system was not yet implemented. This working group was constituted, along with others, to help implement the PUC's restructuring order to open up customer choice of generation suppliers in the context of implementing restructuring principles to drive competition and innovation, including in rate options and in the context of providing open and nondiscriminatory access to the electric system for retail transactions.[6]

In PUC Order No. 22,875 (3/20/98) in DR 96-150, Electric Utility Restructuring, the Commission (at p. 17) determined that "for the convenience of the customers, we will require distribution companies to offer competitive suppliers the option of including their unbundled energy charges on a single consolidated bill, prepared by the distribution company." The Commission then went on to note (at pp. 23-24):

> ...our delegated mandate is to promote competition not to perpetuate monopolies. As the New Hampshire Supreme Court stated:

[6] See for example RSA 374-F:3, II and IV.

> …[L]egislative grants of authority to the PUC should be interpreted in a manner consistent with the State's constitutional directive favoring free enterprise. Limitations on the right of the people to "free and fair competition"... must be construed narrowly, with all doubts resolved against the establishment or perpetuation of monopolies. RSA 374:26 thus should not be interpreted as creating monopolies capable of outliving their usefulness.
>
> Appeal of PSNH, 141 N.H. 13, 19 (1996) (emphasis added) (internal citation omitted).
>
> In this case, we have identified specific circumstances where electric utilities may exploit their privileged status to inhibit the development of a competitive retail electricity market. We will implement special protections to mitigate these anti-competitive practices. Should we determine these special protections are insufficient, we will impose additional pro-competitive measures."

Furthermore, the technical details of the EDI Working Group Report indicate provision of both usage data by TOU period with 2 or 3 periods and well as billing information by TOU rate period. This is expressed in the Report's Glossary of Terms at pp. 47 and 49-50, as well as in the fields to be enabled in EDI 810 transactions that expressly include provisions for reporting usage by TOU period and charges by TOU period, whether 2 or 3 part (pp. 1-3). These excerpts are attached as Attachment 3 and 4 respectively.

Liberty's tariff under Terms and Conditions for Competitive Suppliers also has a section simply entitled "On-Peak / Off-Peak Period Definitions" that states that those "periods shall be as defined in the Company's applicable Rate Schedule."[7] There is no point is providing such a definition if competitive suppliers are not able to use them. Puc 2205.16(c)(2) provides allows "a CPA to define on-peak, mid-peak, and off-peak periods or other pricing options and rate structures that are different from those defined in the utility's applicable tariffs on file with the commission, . . ." subject to certain conditions, including that the CPA cover the cost of such

[7] Tariff at Section 62, v., 7, original page 84.

modifications with the clear implications that if those TOU periods are the same as those defined in the utility tariff, then consolidated billing should be available using those same TOU periods.

Q. How can CPCNH's concerns be addressed?

A. RSA 374-F, IV expressly provides that the Commission (and now also the Department of Energy) "monitor companies providing transmission or distribution services and take necessary measures to ensure that no supplier has an unfair advantage in offering and pricing such services." While we appreciate Liberty's offer to provide TOU usage data outside of the EDI, since the Massachusetts version that they use was apparently never configured to support such, we think it is important for all suppliers to be able to offer TOU energy service rates where the utility is doing the same. Furthermore, as most residential and small business customers generally prefer one bill for all electricity services over separate billing, it would be discriminatory and anti-competitive to not enable such use of the utility consolidated billing system. Therefore, the Coalition urges that the Commission make the roll-out of new TOU rates conditional upon the utility simultaneously enabling the automated provision of usage data (positive and negative) by TOU period and enable billing of TOU period differentiated rates by CPAs and CEPS through consolidated billing.

In its supplemental response Liberty went on to say that it could not change its EDI system without going through a reconvened NH EBT working group. It may be significant to note that the original EDI working group apparently worked by consensus and where they did not have consensus in their original report, the issues were brought to the attention of the Commission for resolution. The decision-making process for a NH EDI working group going forward never seems to have been memorialized. The description of the Change Control process in the main report (at 42) stated that it "is anticipated that the EDI standards will be modified and enhanced as market or regulatory requirements dictate." CPCNH is of the view that the Commission should require those changes necessary to conform with originally anticipated functionality that would still be of value and use to competitive suppliers and CPAs today even if 25 years behind schedule. This would include provision of negative usage data as originally provided for in the 867 historical usage data set, which Unitil does provide, but Liberty has yet to provide through 867, 810, or any other report applicable to actual customers.

IV. Battery Storage

Q. What is the Coalition's position on Liberty's proposed Phase 2 of its battery storage pilot?

A. We are generally supportive of approval of Liberty's Phase 2 of its battery storage pilot. We believe there is considerable customer interest in additional battery storage deployment and would like to work with Liberty to encourage appropriate adoption of BYOD options by CPCNH supply customers. As we understand the Settlement approved in DE 17-189, Liberty would be able to own up to 300 more batteries serving 150 new customers in addition to the 100 now or soon-to-be-served under phase 1 of the program, with two Tesla batteries each, for up to 500 total batteries deployed under Liberty ownership and control. In addition, Liberty is proposing a limited BYOD program for up to 150 residential customers over the three years following Commission approval, understanding that the working group contemplated in the settlement to advance technical requirements for BYOD interconnection, operation, and dispatch has not been constituted been realized.

We suggest the after the first year of phase 2, there be an option to expand the BYOD portion of the pilot to match up to the total number of customers (250) in the Liberty owned battery portion of the pilot, especially if a working group around BYOD can become active and assist Liberty, the Commission, and the Department in developing appropriate tariff provisions for battery interconnection, operation, dispatch, and crediting of BYOD part of the program.

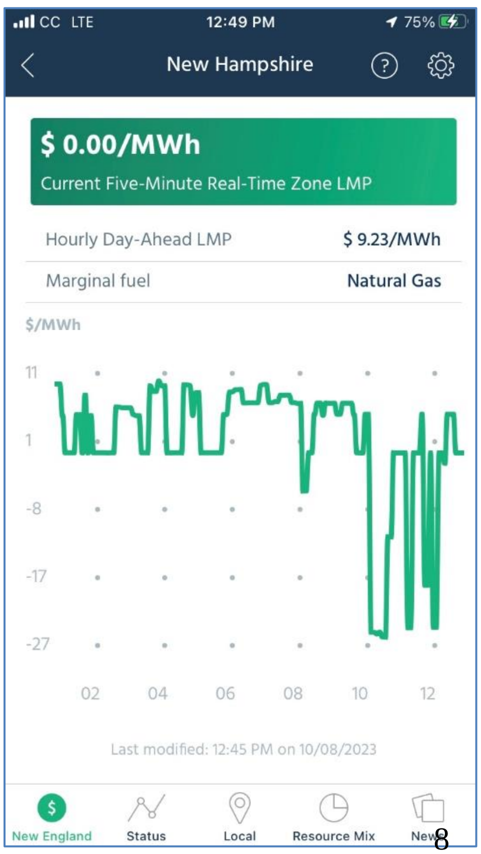
V. Advanced Metering Infrastructure (AMI)

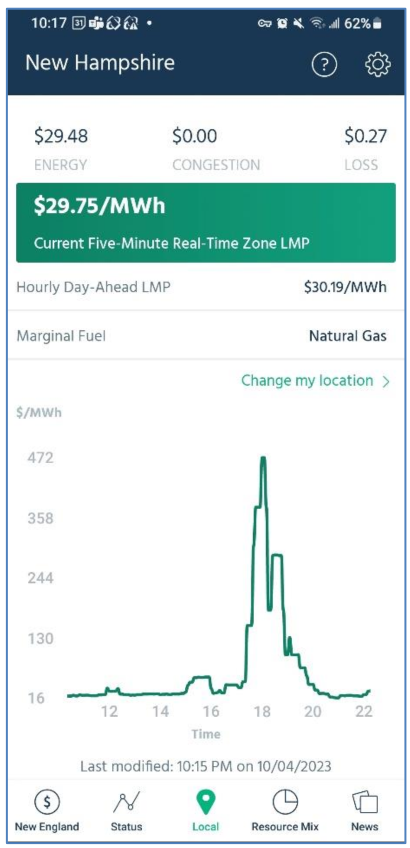
Q. What is CPCNH's position of Liberty's AMI proposal?

A. Again, CPCNH is generally supportive of Liberty's AMI proposal but urge Liberty to engage CPAs, CEPs and other potential users of the granular interval data that will become available with AMI deployment in planning the requirements for such. In particular, we note the graphic provided on p. 11 of the Direct Testimony of D. Balashov and A. Strabone answers the question of "what can an AMI meter do that a conventional meter cannot?" with a response on interval metering that "AMI can disaggregate consumption across time intervals as frequent as 15 minutes." In response to a data request or a question at a technical session, Liberty indicated that was simply an illustrative graphic and not a specification that interval data would only be as granular as 15-minute intervals.

This is relevant because a few years ago, ISO-NE changed its load and generation supply settlement system to settle at 5-minute intervals, requiring 5-minute real time Locational Marginal Prices (LMPs) for the supply side of the equation while still allowing load to settle based on hourly load data. At the time, I inquired ISO-NE about this matter and was told that the system was designed to be able to also settle load at 5-minute intervals. Given this information, I believe that to future proof new AMI deployments, Liberty should enable its new AMI system to be capable of reporting load at the same 5-minute intervals when ISO-NE settlement on the margin occurs. A basic tenant of economic theory and economic efficiency in markets is the optimal price formation occurs when both supply and demand are able to respond to the same price signals. While perhaps not relevant to most retail customers, increasingly DERs, including in particular energy storage and certain types of automated demand response, such a flexible EV and hot water heater charging, may be able to generate considerable value by being able to respond to 5-minute interval pricing which can gyrate between high and low LMPs and well as negative LMPs (where load could get paid for consuming energy) in discrete 5-minute intervals.

Here a couple of visual examples of such fluctuations in LMPs in 5-minute periods:





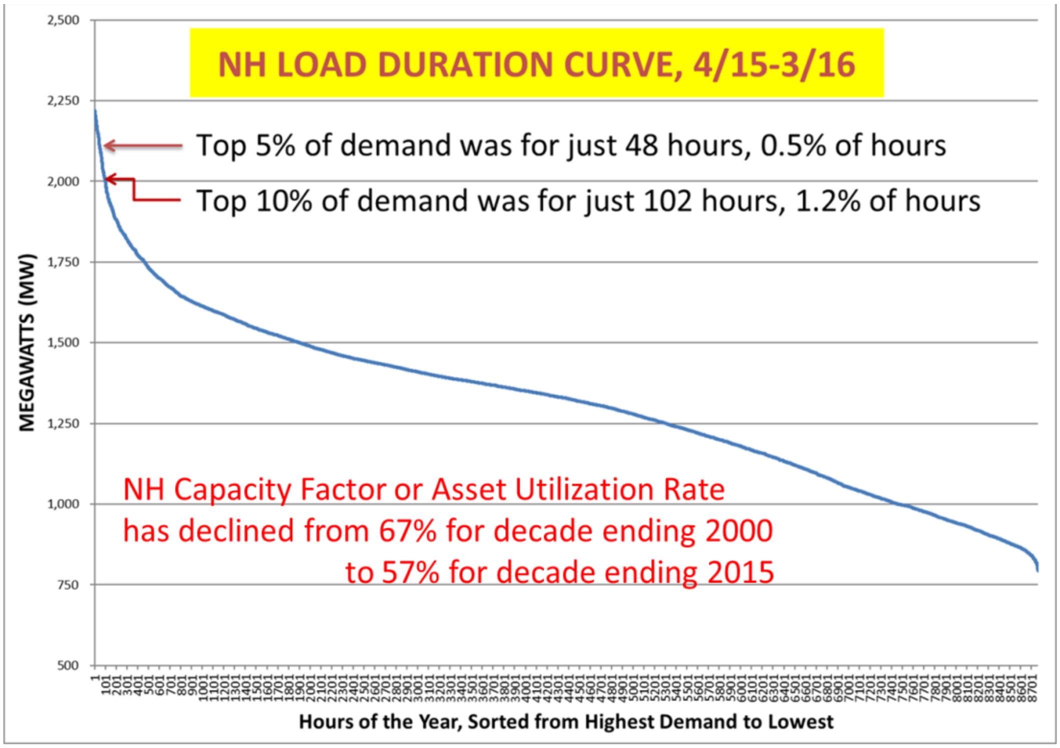
When I inquired of Liberty in the past as to the potential to enable load to settle at 5-minute intervals, they indicated that their load settlement vendor was not capable of performing that functionality, even if the meter data existed. It is worth noting, particularly since Liberty is planning to deploy Itron AMI meters that Itron very recently rolled out a new load settlement module that is capably of settling load at 5-minute intervals (as well as, apparently, negative loads), so we would urge Liberty to consider implementing this upgrade as part of their AMI strategy. Itron's press release on this new load settlement "module" is attached as Attachment 5.

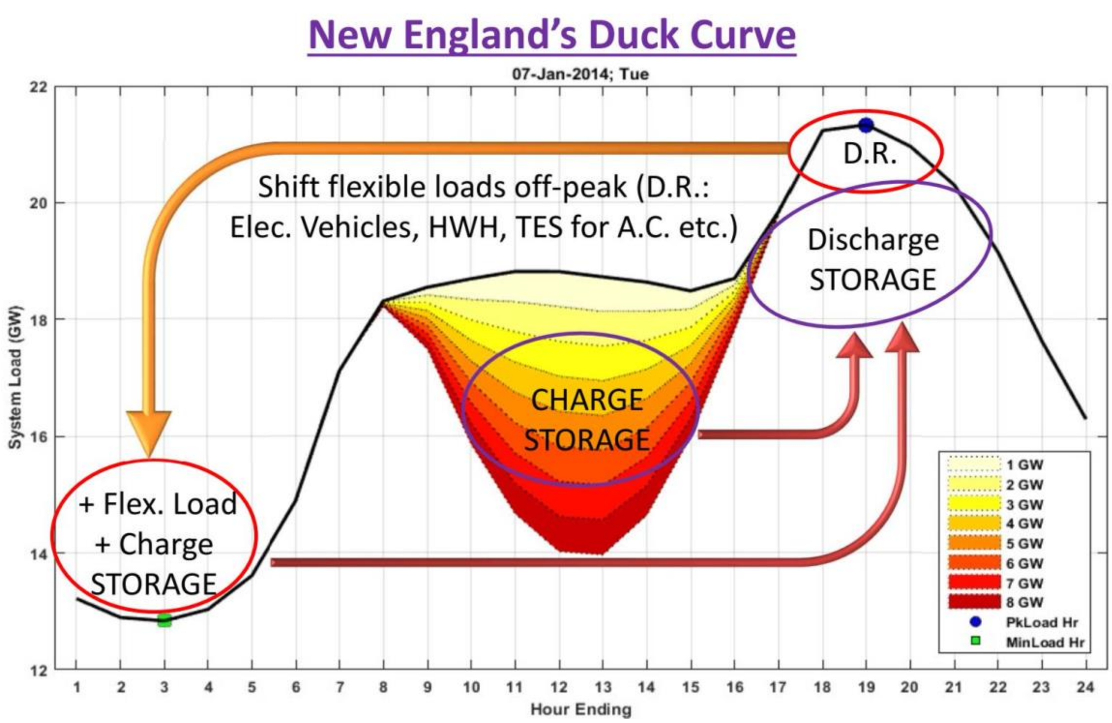
VI. Performance-Based Ratemaking (PBR)

Q. What are your views on Liberty's PBR proposal?

A. We are generally supportive of the PBR proposal and multi-year rate path but are concerned that the positive reward for shortening interconnection time for NM projects greater than 10 kVA, but no more than 100 kVA may represent a relatively easy lift, especially if additional fees to process such applications are approved in DE 22-060 and are used to staff up in this particular area. Another or alternative Performance Incentive Mechanism (PIM) might be based on improvements to Liberty's overall load factor. In previous analysis I found that New Hampshire's average load factor had declined from 67% in the decade ending 2000 to 57% for the decade ending in 2015. That means the fixed cost of distribution and other capacity is being spread over relatively fewer kWh than when we have a high load factor or asset utilization rate.

I haven't had time to update this analysis, but a specific metric should be easy to devise. Starting with 2022 as a base year, Liberty's overall load factor (for all retail load served) could be calculated and the PIM could be an incentive of 1 bp (basis point) increase in ROE for each 1% increase the annual load factor, with at least a proportionate increase coming from load on CPA or competitive supply, up to a 10 bp incentive. This would be an indicator of long-term value increase for all customers by spreading capacity costs over more kWh, rather than fewer, and would be an indicator of Liberty's success in incentivizing peak shaving relative to load growth, resulting in lower capacity costs per kWh over the long-term. The two graphics below illustrate this issue:





VII. Electric Reconciliation Adjustment Mechanism (ERAM)

Q. What are CPCNH's concerns about the proposed ERAM discussed in the testimony of Erica Menard?

A. Generally, we are not opposed to Liberty's proposed ERAM, except for the provision that all NM costs (the compensation paid to net metered customer-generators for power exported to the electric grid) be moved from recovery as part of the energy service rate to the new ERAM. The specific concern is that several issues are pending that may well indicate that some of these costs would be appropriately recovered from utility default service customers and some through the transmission cost adjustment mechanism (TCAM) as discussed in my direct testimony is DE 22-060.[8] Specifically RSA 362-A:9, XXI(a) directed the Commission to "consider the question of whether or not exports to the grid by customer-generators taking default service should be accounted for as reduction to what would otherwise be the wholesale load obligation of the load serving entity providing default service absent such exports to the grid" and to use its best efforts to resolve such question through an order in an adjudicated proceeding by June 15, 2022. This is a question has not yet been resolved but is a mirror image to the provision in RSA 362-A:9, II that output from NM customers on CPA or competitive supply "shall be accounted for as a reduction to the customer-generators' electricity supplier's wholesale load obligation for energy supply as a load service entity, net of any applicable line loss adjustments, as approved by the commission." CPCNH expects to soon be filing a petition for just such approval. In the course of discussing this with representatives of Liberty, Unitil and Eversource, there has been some representation that if

[8] Available at Tab 63 at https://www.puc.nh.gov/Regulatory/Docketbk/2022/22-060.html.

load settlement is changed for NM customers on competitive supply, it would need to be changed for utility default service as well. In such a case, the utility default service customers would see a reduction in the amount of supply purchased through the ISO-NE wholesale market equal to those exports to the grid from NM customers on utility default service but would only have to pay for a portion of that value, with a portion of those costs being shifted to all ratepayers without the benefit of the cost reduction in utility default service supply.

CPCNH has proposed a different paradigm and compensation rate in DE 22-060 for NEM 3.0 rates where the compensation to utility default service NM customer-generators would be reduced to the equivalent to what the supplier of default energy service is paid, so that all of those costs could be recovered from default energy service customers in a manner that holds them neutral on such costs, whether paid to the default service supplier or to NM customer-generators. Furthermore, we have proposed that large NM customer-generators with interval metering be compensated for actual avoided transmission costs and that that cost be recovered through the TCAM. That would still leave some costs, mainly to small customer-generators under NEM 2.0 and 3.0, particularly for distribution and transmission rate credits, and the excess of the energy service rate beyond the equivalent rate paid to the default service supplier, which would be appropriate for recovery from all customers through the new proposed ERAM. Any final resolution of this part of Liberty's proposal could be made contingent on the outcome for NM tariffs going forward in DE 22-060, as these issues are also within the scope of that docket.

VIII. Conclusion

Q. Do you believe the recommendations made in your testimony are consistent with and promote just and reasonable rates?

A. Yes, I do.

Does that conclude your testimony?

A. Yes, it does.