CITY OF LEBANON

51 North Park Street

Lebanon, NH 03766

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April 19, 2021

Hon. Michael Vose
Chair, Science, Technology & Energy Committee
New Hampshire House
107 North Main St.
Concord, NH 03301

RE: **SB 91, adopting omnibus legislation on renewable energy and utilities. Testimony on Part I, IV, and V.**

Dear Rep. Vose & Members of the NH House Science, Technology & Energy Committee,

Good morning. I'm testifying in support of SB 91 on behalf of the City of Lebanon as its Assistant Mayor. This omnibus legislation enjoys broad bi-partisan in the Senate and I commend its passage to you.

Regarding Part V of the bill, it is nearly identical to the House passed HB 315, except it has the OLS drafting error striking "provide" on p. 8, line 16 that this Committee corrected. Either the bill should be amended to correct that or Part V removed all together and rely upon the Senate to pass HB 315.

I'm here in particular to make the case for keeping **Part IV of the bill relative to the purchase of output of limited electrical producers in intrastate commerce and including qualifying storage systems**. I realize this Committee has already voted two similar bills, HB 295, sponsored by Rep. Pearl, and HB 417, sponsored by Rep. McGhee, Inexpedient to Legislative. However, I urge you to take the time to take a closer look at this part and consider amending it to address any concerns that may persist after taking a closer look. Between now and May 27, when this bill must be reported, is the best and last opportunity to consider this matter in this biennium as House rule 36(e) prohibits the reintroduction of legislation voted ITL in first year of the session.

Part IV updates RSA 362-A: 2-a, that currently enables limited producers up to 5 MW to sell to up to 3 intrastate wholesale or retail customers, but includes archaic language dating back to 1979, regarding the PUC conducting an adjudicated proceeding for "wheeling" the power. That was a concept that existed before electric utility industry restructuring was enacted in 1996. It also limits the number of purchasers of such output to 3, without PUC authorization for more, and creates the possibly of such purchasers being relieved of transmission charges for such purchases, even if such limited producer output does not actually decrease transmission charges to the distribution utility. I've attached a copy of the current statutes that Part IV would amend.

More importantly Part IV creates a market-based alternative, that should be free of any cross subsidy, to expanding net metering up to 5 MW. Absent such an alternative the political pressure to further expand net metering is likely to persist and grow.

Twenty-four years ago when I took on the prime sponsorship of HB 485, with then Rep. Bradley as my co-sponsor, that originally created net metering and RSA 362-A:9, we amended RSA 362-A:1, Declaration of Purpose, to read as follows (with emphasis added):

> 362-A:1 Declaration of Purpose. It is found to be in the public interest to provide for small scale and diversified sources of supplemental electrical power to lessen the state's dependence upon other sources which may, from time to time, be uncertain. It is also found to be in the public interest to encourage and support diversified electrical production that uses indigenous and renewable fuels and has beneficial impacts on the environment and public health. ***It is also found that these goals should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3. It is further found that net energy metering for eligible customer-generators may be one way to provide a reasonable opportunity for small customers to choose interconnected self generation, encourage private investment in renewable energy resources, stimulate in-state commercialization of innovative and beneficial new technology, enhance the future diversification of the state's energy resource mix, and reduce interconnection and administrative costs. However, due to uncertain cost and technical impacts to electric utilities and other ratepayers, the general court finds it appropriate to limit the availability of net energy metering to eligible customer-generators who are early adopters of small-scale renewable electric generating technologies.***

While current law still recognizes that net metering is one way to enable such customer choice, the language on limiting net metering to early adopters is long since gone. But as the prime sponsor of the bill that first created net metering, I think we are overdue for a market-based alternative to net metering, especially for projects over 100 kW in size, up to 5 MW in size, and that intentionally avoids any significant cross-subsidy.

Part IV of this bill is an important complement to HB 315, allowing community power aggregations and competitive suppliers to offer local renewable generation to customers as part of their supply options, without gong through the contortions of group net metering, which is not available for generation and storage projects >1 MW up to 5 MW. Just in the past couple of weeks I've been approached by a major developer in West Lebanon, Chet Clem, with River Park, a 38 acre site with over 850,000 s.f. of approved mixed use space. He is very interested in the possibility of securing purchase power agreements for local renewable energy to help power his development, such as through Lebanon Community Power. I was also called last week by a Lebanon resident that owns a site that looks to be quite viable for more than 1 MW of solar (but less than 5 MW) and would like to see that potential power, possibly with storage, sold through Lebanon Community. We are aware of other businesses and property owners with similar interests. Under current law such an arrangement may be possible, but is difficult. Part IV of this bill would make this a much more feasible possibility.

Before going into any more detail on Part IV of the bill, I'd also like to suggest an amendment to Part I of the bill (in red), which move NH forward in terms of enabling customer and utility owned electricity storage and all the benefits it might bring.

Amend RSA 374-H:1, XI as reenacted by Part I, Section 1 of SB 91 (p. 2, line 22) as follows:

XI. "Wholesale electricity markets" means any energy, capacity, or ancillary service market that ISO-New England operates ***or that may operate pursuant to RSA 362-A:2-a*****.**

The reason for this is arises from how the definition is used to direct the PUC as follows:

I. The commission shall investigate ways to enable energy storage projects to receive compensation for avoided transmission and distribution costs, including but not limited to avoided regional and local network service charges, while also participating in wholesale energy markets.

And to consider: "(b) How to compensate energy storage projects that participate in wholesale electricity markets for avoided transmission and distribution costs in a manner that provides net savings to consumers."

There may be very limited or no way to compensate storage projects or realize net savings for avoided transmission costs for storage that participates in ISO-NE (FERC jurisdictional) wholesale markets because the load they serve, i.e. the electricity that they export to the grid is going to typically be counted toward the regional network load (RNL) that is used to determine allocation of transmission costs. HOWEVER, RSA 362-A:2-a as it exists today, and even more so as it would be improved by Part IV of SB 91, enables an intrastate wholesale market (within NH only for DG and storage < 5MW) in which generation or storage that does not participate in ISO-NE wholesale markets is treated as a load reducer and DOES reduce transmission costs and allocation to NH. So just let the PUC consider that as well as there may be greater value in having storage operate as a load reducer than full participant in ISO-NE markets. Storage that only participates with ISO-NE as a regulation resource, i.e. an ATRR or "Alternative Technology Regulation Resource" can still function as a load reducer for reducing allocation of transmission costs, but not if they are being paid for energy or capacity in that ISO-NE market.

Returning to Part IV, I'd also like to suggest a simple amendment (in red) to RSA 362-A:1-a, III as it would be amended (p. 6, lines 22-31) to read as follows:

III. "Limited producer" or "limited electrical energy producer" means a qualifying small power producer***, a qualifying storage system,*** or a qualifying cogenerator, with a [~~total~~] ***maximum rated generating or discharge*** capacity of [~~not more~~] ***less*** than 5 megawatts, ***that does not participate in net energy metering, that is not registered as a generator, asset, or network resource with ISO New England, and does not otherwise participate in any FERC jurisdictional wholesale electricity markets,***

except as a regulation resource. Such non-participation in FERC jurisdictional intrastate wholesale markets may be achieved by retirement from such markets.

This would allow a limited producer not otherwise participating in ISO-NE markets to still be able to serve as a "regulation resource" (i.e. an ATRR) because that doesn't change its function as load reducer for energy markets and relative to transmission costs.

Here are some key features of Part IV:

- It clarifies that a limited producer that participates in direct retail sales or within state wholesale sales cannot also be participating in net metering or the interstate wholesale markets administered by ISO New England. This is essential to avoid "double dipping" for compensation and to respect jurisdictional boundaries.
- It does clarify that for such limited producers, that are exclusively under state jurisdiction, can sell within the state at retail or at wholesale (intrastate wholesale sales) to electricity suppliers, which is the case today, but it is not explicitly addressed in terms of the regulatory structure.
- It gives credit, where credit is due, for actual avoided transmission costs, but only if they are actually realized.
- It allows storage under 5 MW that is not participating in net metering or ISO New England markets to engage in these bilateral within-state electricity supply transactions.
- It puts storage and distributed generation under 1 MW participating in transactions under this section of the law on an equal basis with such distributed resources that are participating in net metering.
- It gives the PUC appropriate authority to oversee this and puts the burden of accounting for this on the load serving entities that serve such limited producers and any retail customers.

There may be some confusion or concern about the jurisdictional issues. In response I highlight the following:

- The Federal Power Act, 16 U.S. Code § 824, (https://www.law.cornell.edu/uscode/text/16/824) has long been quite clear that while FERC has exclusive jurisdiction over wholesale sales of electricity in interstate commerce, the states have exclusive jurisdiction of wholesale sales in intrastate commerce.

- (b)(1) "The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy . . . The Commission . . . shall not have jurisdiction, over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce . . ."

- (d) Ae wholesale sale "means a sale of electric energy to any person for resale"

- (c) "electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof"

- The US Supreme Court has recently reiterated this jurisdictional boundary in FERC v. EPSA, 577 U. S. ____ (2016):

Under the statute [the FPA], the Commission has authority to regulate "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce." 16 U. S. C. §824(b)(1).

. . . the Act also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction. As pertinent here, §824(b)(1)—the same provision that gives FERC authority over wholesale sales—states that "this subchapter," including its delegation to FERC, "shall not apply to any other sale of electric energy." Accordingly, the Commission may not regulate either within-state wholesales sales or, more pertinent here, retail sales of electricity (*i.e.*, sales directly to users). See *New York*, 535 U. S., at 17, 23. State utility commissions continue to oversee those transactions.

. . . as earlier described, [FPA] §824(b) limit[s] FERC's sale jurisdiction to that at wholesale," reserving regulatory authority over retail sales (as well as intrastate wholesale sales) to the States. *New York*, 535 U. S., at 17 (emphasis deleted); see 16 U. S. C. §824(b); *supra,* at 3. FERC cannot take an action transgressing that limit no matter its impact on wholesale rates. [p. 17] . . .

The Act makes federal and state powers "complementary" and "comprehensive," [p.27]

- ISO New England through its FERC sanctioned tariffs, rules and operating procedures has drawn a bright line. Generation that is not less than 5 MW in size and connected to state jurisdictional distribution grid does not have to register with the ISO as a generator and instead operates as a "load reducer" for the purposes of the interstate wholesale electricity markets that it administers.

- While there has been some confusion as to how distributed generation (< 5MW and not registered with ISO New England is treated with regard to calculation of RNL (Regional Network Load) for purposes of transmission cost allocation, Eversource and other transmission owner in New England have proposed language to clarify the Open Access Transmission Tariff (OATT) to make clear that the output of (and the load served by) DG not registered as a "Generation Asset" with ISO New England onto a distribution grid would not contribute to RNL. That is to say, such DG output would reduce transmission costs allocated to the distribution utility from what they would otherwise be. Using the basic principle of cost causation, Part IV of SB 91 would simply give around 95% of the value of such savings to the DG or storage system creating such savings. The remaining value (~ 5%, the delta between the net retail load reduction and what would have been purchased from ISO-NE markets, i.e. transformation and line losses) would accrue to all ratepayers.

- Here is the tariff language addition that has been proposed and that all other members of the PTO-AC (Participating Transmission Owners Administrative Committee) unanimously voted on April 9th:

- "Network Customer's Monthly Regional Network Load shall exclude (i) load offset by any resource that is not a Generator Asset, and (ii) load offset by the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset."

- I've attached the slide deck that further explains this (quote above is from slide 5).

- Here is another slide from an earlier presentation to the Transmission Committee that further illustrates how this would apply:

Examples

Example	ISO-NE Registration	RNL Impact
Rooftop solar array (10 kW)	Not registered	Not included in RNL calculation
Stand-alone distribution-connected PV array (4 MW)	SOG	Included in RNL calculation
Stand-alone distribution-connected PV array (4 MW)	Not registered	Not included in RNL calculation
1 MW distributed generator co-located with 2 MW load	Not registered	Not included in RNL calculation
3 MW distributed generator co-located with 2 MW load	Generation (1 MW) registered as SOG	Net generation included in RNL calculation
530 MW generator with 30 MW online station service load	Generation (500 MW) registered as Generator Asset	Net generation included in RNL calculation
2MW Stand-alone Battery storage	Not Registered	Not Included in RNL
3MW Stand-alone Battery storage	Only Registered as ATRR	Not Included in RNL
3MW Stand-alone Battery storage	Registered as a Generator Asset	Included in RNL calculation

SOG: Settlement Only Generator
ATRR: Alternative Technology Regulation Resource

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Please do not hesitate to be touch if you have any questions. I do hope to work with the committee and interested stakeholders to further consider and refine Part IV of the bill. Thank you!

Yours truly,

Clifton Below

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CHAPTER 362-A
LIMITED ELECTRICAL ENERGY PRODUCERS ACT

362-A:1 Declaration of Purpose. – It is found to be in the public interest to provide for small scale and diversified sources of supplemental electrical power to lessen the state's dependence upon other sources which may, from time to time, be uncertain. It is also found to be in the public interest to encourage and support diversified electrical production that uses indigenous and renewable fuels and has beneficial impacts on the environment and public health. It is also found that these goals should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3. It is further found that net energy metering for eligible customer-generators may be one way to provide a reasonable opportunity for small customers to choose interconnected self generation, encourage private investment in renewable energy resources, stimulate in-state commercialization of innovative and beneficial new technology, enhance the future diversification of the state's energy resource mix, and reduce interconnection and administrative costs.

Source. 1978, 32:1. 1994, 362:2. 1998, 261:1, eff. Aug. 25, 1998. 2010, 143:1, eff. Aug. 13, 2010.

362-A:1-a Definitions. –

In this chapter:

III. "Limited producer" or "limited electrical energy producer" means a qualifying small power producer or a qualifying cogenerator, with a total capacity of not more than 5 megawatts.

362-A:2-a Purchase of Output by Private Sector. –

I. A limited producer of electrical energy shall have the authority to sell its produced electrical energy to not more than 3 purchasers other than the franchise electric utility, unless additional authority to sell is otherwise allowed by statute or commission order. Such purchaser may be any individual, partnership, corporation, or association. The commission may authorize a limited producer, including eligible customer-generators, to sell electricity at retail, either directly or indirectly through an electricity supplier, within a limited geographic area where the purchasers of electricity from the limited producer shall not be charged a transmission tariff or rate for such sales if transmission facilities or capacity under federal jurisdiction are not used or needed for the transaction. The public utilities commission shall review and approve all contracts concerning a retail sale of electricity pursuant to this section. The public utilities commission shall not set the terms of such contracts but may disapprove any contract which in its judgment:

(a) Fails to protect both parties against excessive liability or undue risk, or

(b) Entails substantial cost or risk to the electric utility in whose franchise area the sale takes place, or

(c) Is inconsistent with the public good.

II. Upon request of a limited producer, any franchised electrical public utility in the transmission area shall transmit electrical energy from the producer's facility to the purchaser's facility in accordance with the provisions of this section. The producer shall compensate the transmitter for all costs incurred in wheeling and delivering the current to the purchaser. The public utilities commission must approve all such agreements for the wheeling of power and retains the right to order such wheeling and to set such terms for a wheeling agreement including price that it deems necessary. The public utilities commission or any party involved in a wheeling transaction may demand a full hearing before the commission for the review of any and all of the terms of a wheeling agreement.

III. Before ordering an electric utility to wheel power from a limited electric producer or before approving any agreement for the wheeling of power, the public utilities commission must find that such an order or agreement:

(a) Is not likely to result in a reasonably ascertainable uncompensated loss for any party affected by the wheeling transaction.

(b) Will not place an undue burden on any party affected by the wheeling transaction.

(c) Will not unreasonably impair the reliability of the electric utility wheeling the power.

(d) Will not impair the ability of the franchised electric utility wheeling the power to render adequate service to its customers.

Source. 1979, 411:1. 1998, 261:5, eff. Aug. 25, 1998.

Proposed changes to Monthly Regional Network Load calculation

Frank Ettori
(on behalf of Avangrid, Eversource, National Grid, VELCO, and Versant)
4/6/2021

Introduction

- Why are we here?
  - TO's responding to the Internal Market Monitor's spring 2020 Quarterly Markets Report: Transmission Cost Allocation Issues for Behind-the-Meter Generation (Markets Committee, August 13, 2020)*

- Why is it an issue?
  - Affects cost allocation for transmission.
  - Inconsistent interpretation of tariff language

*IMM Quarterly Markets Report: https://www.iso-ne.com/staticassets/documents/2020/07/2020-spring-quarterly-markets-report.pdf

Changes from previous proposal

Background

- Regional Network Load (RNL) defined in Section I of the Tariff
- Monthly Regional Network Load (Monthly RNL) defined in Section II.21.2 of the Tariff
- Monthly RNL used to calculate RNS payments in Section II.21.1

Change from previous proposal to focus on definition of Monthly RNL

- Add additional specificity to definition of Monthly RNL rather than definition of RNL
- Eliminate "behind-the-meter" term from definition of RNL
  - Eliminates need for a new defined term
  - Avoids potential conflicts with usage of "behind-the-meter" elsewhere in tariff
- Better aligns RNL definition to FERC *pro forma* OATT language

No change to substance of prior proposal

Proposed tariff changes to RNL

Section I General Terms and Conditions

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses). ~~and shall not be credited or reduced for any behind the meter generation.~~ A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

Tariff language to Monthly RNL

- **II.21.2 Determination of Network Customer's Monthly Regional Network Load:** Network Customer's "Monthly Regional Network Load" is its hourly load (including its designated Regional Network Load not physically interconnected with the PTF under Section II.18.3 of this OATT) coincident with the coincident aggregate load of all Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak"). Network Customer's Monthly Regional Network Load shall exclude (i) load offset by any resource that is not a Generator Asset, and (ii) load offset by the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset. For Regional Network Load located within the New England Control Area, the Monthly Regional Network Load of all Network Customers within a Local Network shall be calculated by the associated PTO. For Regional Network Load located outside of the New England Control Area, the Monthly Regional Network Load of all Network Customers shall be calculated by the associated PTO (in consultation with the ISO and the associated Balancing Authority).

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

History

- When *pro forma* was written, resource mix was different
- We now have:
  - More customer-owned small-scale generation, especially renewables
  - More focus on state energy policies

TO Proposal More Closely Aligns Monthly RNL with other load calculations

- Same loads will be used to calculate Monthly RNL and energy market settlement
- Monthly RNL will more closely align with load used for FCM cost allocation
- Monthly RNL will more closely align with transmission system planning models
  - Transmission system planning models currently include reductions for energy efficiency and PV

TO Proposal Minimizes Impact to Existing and Future Resources

Existing resources

- No additional metering required for existing resources
- No impact to energy efficiency or demand response resources

Anticipated treatment of distributed energy resource aggregations (DERAs) under FERC Order No. 2222

- Energy market load is calculated from positive net output from registered generation and tie line flows
- DERA with positive net output is akin to a registered generator with positive net output, receives payment from energy market, and would contribute to load calculation
- DERA positive net output will be included in the Monthly RNL calculation
- Load reductions included in a DERA load asset would continue to reduce Monthly RNL, as they do today

Schedule

- Nov 17: PTO-AC discussion
- Dec 10:
  - Introductory discussion at Transmission Committee
- Jan:
  - Introductory discussion at Markets Committee
  - 1/26: Follow-up discussion at TC
- Feb:
  - Feedback from TC
  - Revised proposal at MC
- Mar 23: Revised proposal at TC
- April 6&27:
  - 4/6 Discussion at MC
  - 4/9 Vote at PTO-AC
  - 4/27 Vote at TC
- May 11: Vote at MC
- June:
  - 6/3 Vote at NPC
  - File at FERC
- August: Effective date

CITY OF LEBANON

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June 25, 2021

Director Jared Chicoine
Office of Strategic Initiatives
107 Pleasant Street
Johnson Hall, 3rd Floor
Concord, NH 03301

RE: **Comments on update to NH Energy Strategy**

Dear Director Chicoine,

On behalf of the City of Lebanon and its Energy Advisory Committee I offer the following comments on updating the New Hampshire 10-year state energy strategy. The particular focus of these comments is on how state policies can better enable consumer and community choice to harness the power of competitive markets to drive innovation and the most cost-effective energy and climate solutions.[1] New Hampshire is somewhat uniquely situated to help drive the development of robust retail and wholesale energy markets that better enables the most cost-effective energy resources to serve our needs, including the full array of distributed energy resources (DERs), while simultaneously supporting accelerated decarbonization of our energy system to enable communities like Lebanon to best meet aggressive climate action goals.

While the City generally associates itself with the comments of the Town of Hanover (filed on 6/22) and those of the Clean Energy New Hampshire filed in May, we may deviate a bit in our focus on enabling a more robust in-state wholesale and retail market for distributed energy resources that reflects and works with the inter-state wholesale electricity market operated by ISO New England. New Hampshire's energy strategy might embrace the vision of ***Shared Integrated Grid***, first articulated by the world's leading electricity research body, the Electric Power Research Institute, supporting by most of the major electric utilities in North America. Prof. Amro Farid of the Thayer School of Engineering at Dartmouth, a volunteer consultant to the City of Lebanon, detailed the case for the shared integrated grid as "the leading industrial concept for New Hampshire to achieve its objectives" in his testimony in DE 19-197 concerning the development of a Statewide Multi-use Online Energy Platform.[2]

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[1] Please see the attached "Declaration on Energy Choice & Competition" that argues that "Open, competitive energy markets are an essential component of any policy seeking to mitigate climate change risk through reduced emissions of greenhouse gases. First, because energy innovations simply cannot spread if markets are closed. Second, because there could exist no better incentive for rapid acceleration of energy innovation than the enormous potential offered by vast, growing, open energy markets, ready to adopt and scale up the best innovations. Finally, any policy oriented towards reductions in GHG emissions can only work if markets are open to innovation and transformation, and not impeded by bureaucratic rules and monopoly privileges."

[2] See pages 6-13 in his 8/17/20 testimony found at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TESTIMONY/19-197_2020-08-18_LEBANON_LGC_REV_TESTIMONY_FARID.PDF.

Dr. Farid also summarized this concept and related it to existing NH constitutional and statutory policy in his testimony on HB 315 as introduced, which is attached to these comments.[3] He summarized the Shared Integrated Grid at page 12 as consisting "of 1) network-enabled distributed energy resources and devices, 2) customer engagement in time-responsive retail electricity services (e.g. real-time pricing), and 3) community-level coordinated exchanges of electricity." In reviewing this testimony, as it is quite relevant to NH's energy strategy moving forward, please ignore the specific concerns about HB 315 as introduced on page 3-5, as all of those issues were satisfactorily resolved in the amended language as passed by the House and Senate.

A specific part of this vision that seems particularly consistent with NH's policy and energy strategy as articulated to date is the further development of retail and intrastate wholesale electricity markets through the concept of Transactive Energy, which can be defined as:

> "A system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter."[4]

This is important because supply and demand must constantly be balanced in real time and our electric grid can be expected to become an increasingly important part of our energy system as transportation and space heating (through air and water source heat pumps) are expected to increasingly be provided by electric power in conjunction with shifting them off fossil fuels.

Appropriate price signals, visible to both suppliers and load, are essential to economically efficient price formation. There is a very strong temporal and dynamic aspect of electricity costs. Presently New England has a fairly robust bulk wholesale market administered by ISO-NE, but the 5-minute price signals that are seen by bulk generators and barely visible or translated to retail load. Economics 101 teaches that both supply and demand need to see relevant price signals to achieve optimal price formation and market efficiency.

For example, a very strong marginal price signal at the wholesale level, for transmission services in which embedded costs are recovered based on load's shares of the single hour of highest demand each month (coincident peak), get turned into a flat per kWh rate the retail level. This is also true with the Forward Capacity Market, where future generation capacity costs are allocated based on load's share of the single hour of highest demand, yet most load sees this cost as a flat per kWh charge, giving no signal to load (or retail storage), or net metered generation, that there is temporal value to capacity (and energy).

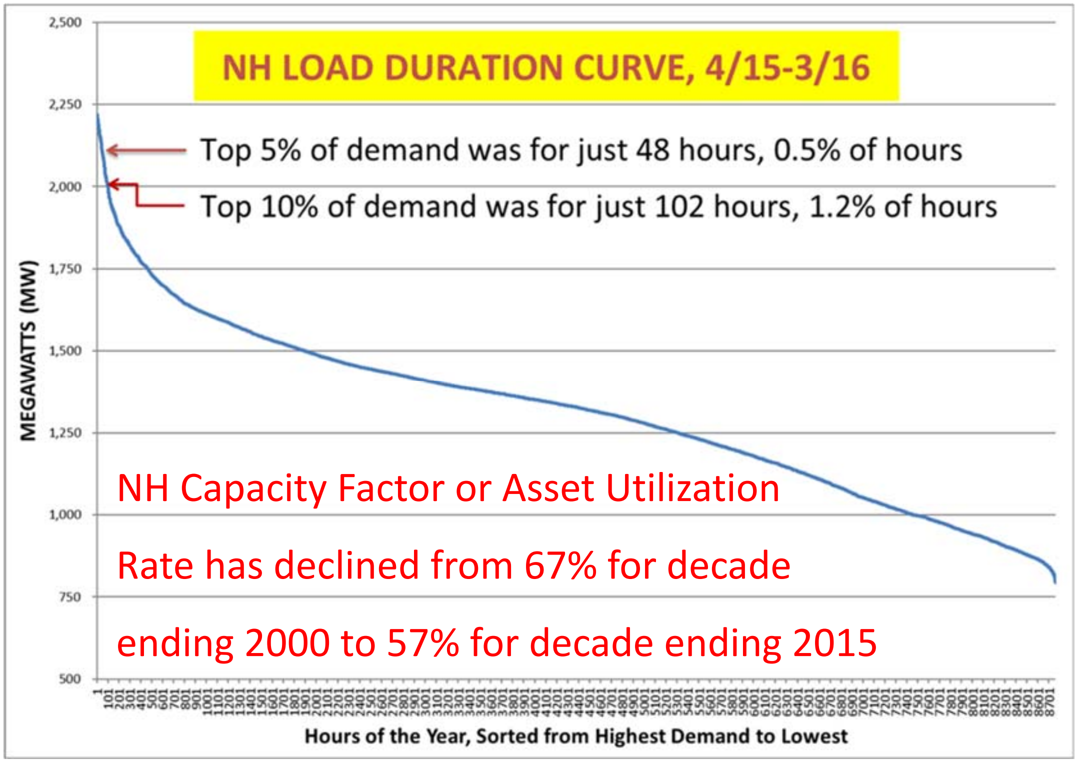
The current state energy strategy points out at page 10:

> "The most effective near-term energy management strategy for New Hampshire is to efficiently and fully utilize existing infrastructure. Maximizing infrastructure utilization improves efficiency while helping reduce environmental impacts."

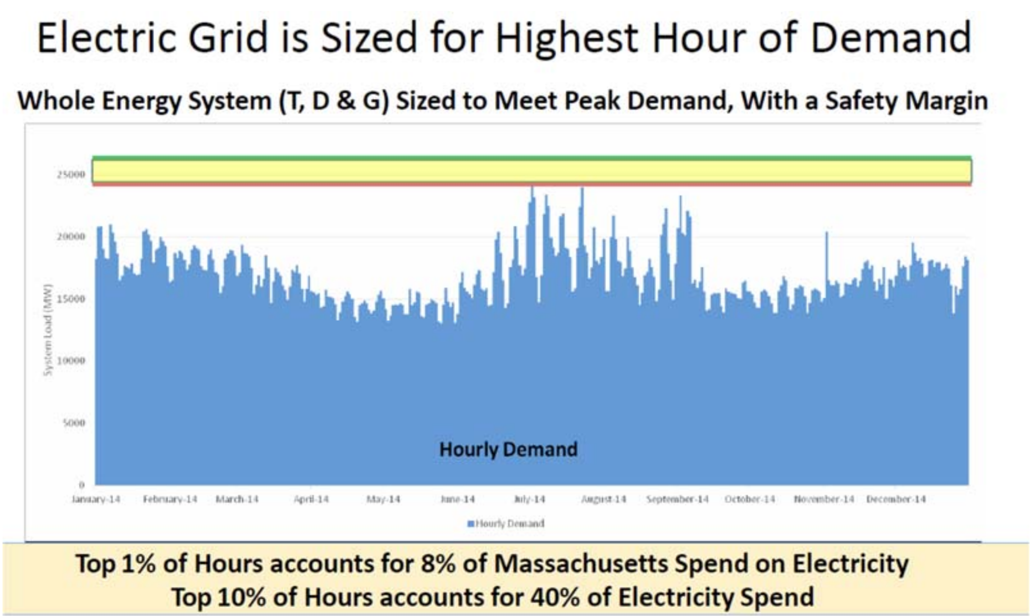
While this statement is made with respect to transportation, that same can be said for the electricity system. The vast majority of electric costs relate to the capacity of the system to meet peak demand, across generation, transmission, and distribution. New increments of capacity tend to be much more expensive than existing capacity. Asset utilization rates, also known as load factors, have tended be decline in New Hampshire and the rest of New England, as peak demand has grown faster than overall load. The result of this is that capacity costs are spread over fewer total kWh resulting in higher costs per

[3] Available at: https://drive.google.com/file/d/10duDea9XTIbBNk1e4D-K2foxQlSh-hLp/view?usp=sharing.
[4] From: https://s3.amazonaws.com/2018-transactive-energy-conference/01+TESC+18+GWAC+Foundational.pdf.

kWh. Although somewhat dated the following graph (prepared by me) illustrates NH's load duration curve:



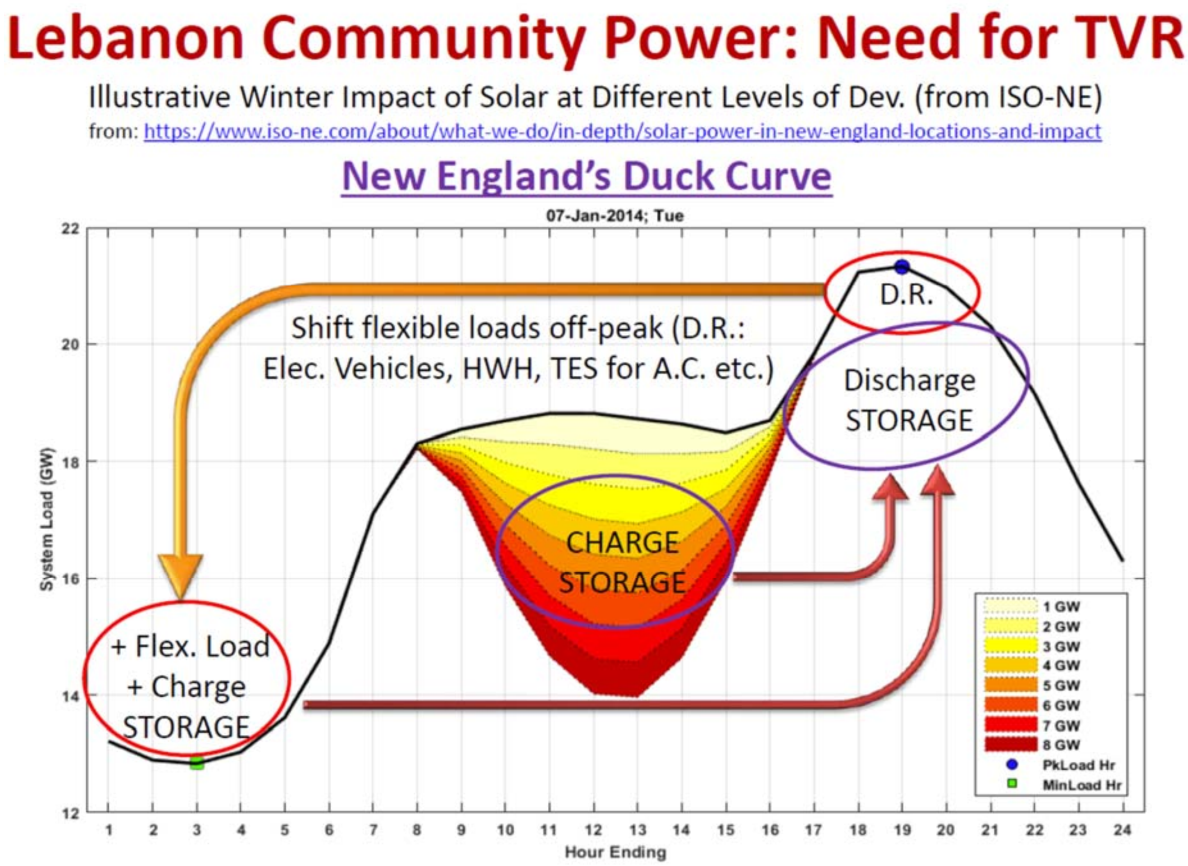
Here is another illustration of the issue[5]:



If we can reverse this trend and grow price responsive flexible load such as vehicle charging and even cooling and heating loads (through thermal storage) during off-peak times, filling in the valleys such as is

[5] From MA Energy Storage Initiative 9/27/16 presentation: https://www.mass.gov/files/documents/2016/09/xd/9-27-16-storage-presentation.pdf.

illustrated below, that can significantly help lower the average cost per kWh and support increased cost-effective integration of distributed renewables.



The Rocky Mountain Institute, among others has, has tried to quantify the enormous opportunity and economic value of enabling demand flexibility (a.k.a. demand response)[6] as have others. Interval metering, or Advanced Metering Infrastructure (AMI), including enabling near real time customer access to such meter data, is key to enabling these benefits as discussed in Grid Modernization, as are time varying rates that reflect the temporal value of capacity (for T, D & G) and energy.[7]

As an intervenor in Liberty's battery storage and TOU rate pilot case, DE 17-189, the City worked closely with Liberty Utilities and the Consumer Advocate to design the 3-part TOU rate that the Commission approved in that case as well as in DE 19-064 for residential EV charging.[8] This TOU rate design, though

[6] See "The Economics of Demand Flexibility: How 'Flexiwatts' Creates Quantifiable Value for Customers and the Grid" available at: https://rmi.org/insight/the-economics-of-demand-flexibility-how-flexiwatts-create-quantifiable-value-for-customers-and-the-grid/

[7] See also: "Expanding Customer Choices in a Renewable Energy Future," Ahmad Faruqui, Principal, and Mariko Geronimo Aydin, Senior Associate, The Brattle Group, in Leadership in Rate Design, A Compendium of Rates Essays, Supplement to Public Power Magazine, May-June, 2019. Available here: https://www.publicpower.org/system/files/documents/Leadership-in-Rate-Design.pdf.

[8] The Liberty TOU rate model is described here: Technical Statement Regarding Time-of-Use (TOU) Model, available at: https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_GSEC_TECH_STATEMENT_TOU.PDF. The TOU rate model is an Excel spreadsheet with data for each hour of the year for T, G & D rate components. Cost causation is reflected in each of the components. The Regulatory Assistance Project characterized it this way in their recent publication "Rate Designs for Modern Grid, "[t]he Liberty storage pilot rate design accepted by the New Hampshire PUC is the most advanced

not dynamic, is an important step forward in developing meaningful time varying rates that load can respond to.

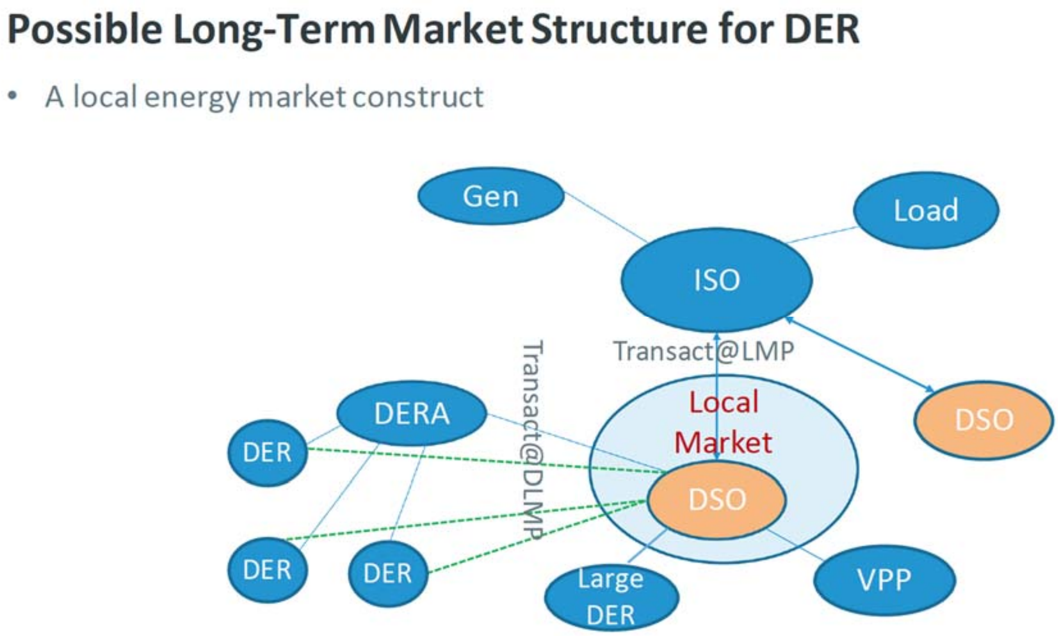
Another key to delivering appropriate price signals to load and other DERs is for the State Energy Strategy to support retention of maximum state authority and jurisdiction over both retail and within-state wholesale sales of electricity and use that jurisdiction to better enable a shared integrated grid. Pursuant to the Federal Power Act, states have exclusive jurisdiction over retail sales, the electric distribution system serving retail customer and intrastate wholesale sales of electricity, meaning power generated within the state for consumption within the state. As a practical matter that means generation under 5 MW in output capacity, that is connected to the distribution grid, and not registered with ISO-NE as a generator asset. This means that such generation can function as a load reducer relative to ISO-NE energy markets and transmission allocation. This is discussed in more detail in my testimony on SB 91, Part IV, which as passed by the Senate would have accelerated a market-based approach to enabling up to 5 MW distributed generation. This is attached to these comments. The final version of the bill instead creates a study commission to consider some the questions raised by that bill. Here are some additional comments I wrote in that regard:

The regulatory gap we are trying to fill with SB 91 Part IV is an important one that ISO New England's Director of Advanced Technology Solutions, Tongxin Zheng, described in a presentation last summer in the Electric Power Research Institute (EPRI) – Stanford University's Digital Grid Webinar series. Specifically he calls for development of "**local energy markets**" for distributed energy resources, **regulated by the New England states**, but in coordination with ISO-NE interstate wholesale markets for bulk power generation. The slide deck that went with that presentation can be found here: https://www.epri.com/research/sectors/technology/events/6182D0F6-9731-4819-83FD-3A126EEEF613 by clicking on "09-Digital Grid - The Value of Resilience for Customer DERs Panel (August 5, 2020)" Here are a few key quotes transcribed from it below.

- The recording is online here (click on attachments > media > play "Digital Grid - Customer DERs in Wholesale Markets panel").
- Transcribed parts of ISO-NE presentation and the Q&A follow below.
- The Q&A mentions Federal / state jurisdiction— and alludes to how Europe is further along in implementing Distribution System Operator (DSO) frameworks. In NH the electric distribution utilities are the DSOs.
- ISO-NE's presentation walks through the structural limitation of the current approach, reliant upon aggregators bidding DER assets into wholesale markets — which is that dispatch signals from ISO-NE could cause issues on the distribution grid and local congestion that requires "significant adjustment" deviating from the original dispatch instruction, all compounded by a lack of DER visibility and "mismatch between the market model and the physical".
- This leads to the conclusion that the scheme described above requires "proper ISO/DSO/[DER aggregator] coordination" and "can be efficient in the short run" — but to "fully resolve the TSO/DSO coordination issue, ***local energy markets could be established*** in the future when a large number of DERs participate in the wholesale markets."

modern rate design in New England, and closest to the Maryland 20 rate designs" that they characterize as one of the most well designed TOU ratesThe Regulatory Assistance Project's 10/20/2020 policy brief "Time-Varying Rates in New England: Opportunities for Reform" presents a nice overview of the Liberty TOU rate at 7-8 and summary of IR 20-004 at 14. (https://www.raponline.org/knowledge-center/time-varying-rates-in-new-england-opportunities-for-reform/).

That suggestion is accompanied by the conceptual schema below:



The slide above begins at 1:11:45 — transcription below:

1:11:45 — Tongxin Jen (ISO-NE): *We should have two levels of market structure... the existing wholesale market, and the DSO becomes either a market participant or a market operator for a local energy market. So the DSOs will monitor the distribution system and dispatch [DER aggregators] and also resources connected into their system, and try to resolve any issues in the distribution system — a D-LMP concept. However, the DSO will be coordinating with the ISO, or transacting at the T and D boundary at the LMP.*

So in this type of coordination the ISO market will have very few responsibilities... so will not face the complexity created by the DER integration. This concept looks simple, but there are challenges especially from the state and policy perspectives, . . . to fully resolve the DSO / TSO coordination issue, the local energy market should be tackled in the future...

The Q&A that immediately follows is also interesting — excerpts from the first few minutes are transcribed below, where CAISO broadly agrees with ISO-NE and they discuss Federal / state jurisdiction:

- **Q: A consistent theme is the need for market evolution and role of market operator as DSO, which we have in Europe but not really in the US. What kind of interventions are necessary in order to establish this role formally in each of these areas?**
- 1:15:45 — Jill Powers (CAISO): "*I think Tongxin really laid out what the challenge were and it's not just one agency that will be able to resolve this issue... [discusses the scope of coordination and metering necessary to implement DER aggregator model and practical challenges with participation]... absent having all of that in place there is real reluctance to even open up the ability for these types of resources to participate in the market. So it's going to be larger than just the ISO and working in partnership with utilities — it's going to take a lot of regulatory effort*

at the state level to really put these frameworks into place. As John laid out, we really should be looking at long-term vision. We've tried to move forward incrementally into these participation models, but really we need to get to that long-term vision to really have the direction and roadmap as to what we're going to do to get there."

- 1:18:15 — Tongxin Jen (ISO-NE): *"Jill pretty much covered it. For me, I think this is a regulatory issue especially though. If DERs participate in the wholesale market directly, that's FERC jurisdiction. But if you want to set up a local energy market, that actually falls in the hands of the state. . . .*
- **Q: paraphrased: what is the regulatory innovation you think should happen to achieve this vision?**
- 1:21:20 — John Goodin (CAISO): *I think the regulatory innovation has to be the ability to capture avoided cost value down at the lower tiers. . . . we need resources that can participate and provide both capacity and energy and capture those values and do that without having to present themselves and integrate with all the complexity in the wholesale markets. So the regulatory hurdle or mechanism is again, how can DR and DER capture avoided cost value, so while they don't have to explicitly earn a capacity payment out of a wholesale market but by their actions, and by reshaping load curve of that customer or in that distribution system under that DSO, that they are reducing the need for peak capacity. . . . So how do these DER entities capture value — for avoiding the need for RA, or avoiding the need for ancillary services by lowering requirements on the system through lower loads, less volatility, lower ramping requirements and ramping energy needs. And I think that's one of the biggest challenges: how to express that value for these providers by allowing them to participate in their tier, avoiding some of these costs, and getting them compensation for doing that — instead of squeezing every tiny little device into the wholesale market. And I think that's the challenge that we face: how to get that value as avoided cost value.*

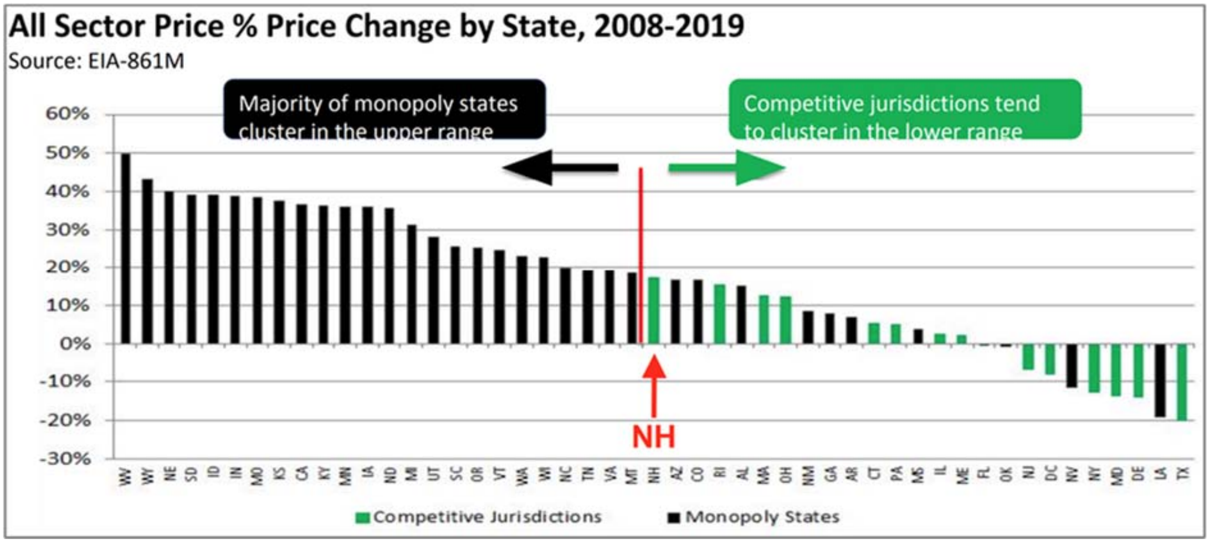
FERC Order 2222, directing wholesale markets like ISO New England's to enable aggregated DERs to participate in FERC jurisdictional interstate wholesale energy markets, can be seen as a work-around for the fact that DERs and retail load are not enabled by state policy to see the appropriate temporal price signals from ISO-NE. Price-responsive demand (PRD)participating in ISO-NE markets is much the same issue. My comments to the ISO-NE on PRD in 2009 when I was a NH PUC Commissioner are still relevant in this respect.[9]

[9] And can be found at: https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2009/jun9102009/a14b_nh_puc_presentation_06_10_09.ppt. Included with these slides are information about thermal energy storage for air conditioning loads, a commercially viable permanent load shifting technology of potentially enormous value and cost-effectiveness if given access to appropriate price signals. I note that the hottest and highest load days of the summer are also when thermal power plants (steam generators) operate at their lowest efficiency of the year because of the proportionally greater energy loads for air based cooling of condensate. It is also when the line and transformation (of voltage) losses are proportionately greatest due to peak loading of the equipment combined with high ambient temperatures, so least useable kWh per btu combusted. Just moving flexible load to off peak hours in the middle of the night results in significantly greater thermal efficiency of everything, including air conditioning equipment.

The more load that sees appropriate price signals on the cost of peak demand, the more that steep part of the curve get flattened and the pressure on adding capacity (and cost) to meet peak decreases. Roughly 40% of New England summer peak is air conditioning and cooling loads. As the slide deck illustrates there are cost effective commercial technologies available to shift AC loads off peak on a daily basis, but they only make

Community Power Aggregation, as enabled by RSA 53-E can play a key role in helping develop the Shared Integrated Grid and market based approaches to cost-effective integration of DERs.

New Hampshire does not appear to have benefitted as much from its electric utility restructuring as other states, as seen in this chart developed by the from the Retail Energy Supply Association:



The current state of the NH retail electricity market is evaluated in the testimony of Samuel Golding of Community Choice Partners in DE 17-179.[10]

A couple of recent studies find that DERs can be cybersecure, cost-effective and improve the reliability and reliance of our electric grid while helping accelerate decarbonization of the Grid.[11]

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economic sense if the underlying cost causation can "seen" or the value recognized in retail rate. A prime example of this is the fact that larger C&I customers have demand charges that are the same whether the demand is in the middle of the night (such as to make ice for thermal storage for AC loads) vs. at coincident peak, so there is no financial reason to shift facility (of vehicle charging) peak demand off-peak, where it might be feasible if distribution demand charges and transmission charges where based on share of coincident peaks. The current rate regime is like saying all airline flights most be the same price regardless of whether on-peak or off-peak, resulting low load factors (asset utilization rates) and the need to build a bunch of extra capacity (# of airplanes and terminal size) just to meet high peak demand with no price differential.

[10] See current state of retail market competition in New Hampshire starting at p. 11 of his testimony found here: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TESTIMONY/19-197_2020-08-18_LEBANON_LGC_REV_TESTIMONY_GOLDING.PDF

[11] See WHY LOCAL SOLAR FOR ALL COSTS LESS: A NEW ROADMAP FOR THE LOWEST COST GRID at https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_ES_Final.pdf and

D. J. Thompson, W. C. H. Schoonenberg and A. M. Farid, "A Hetero-Functional Graph Resilience Analysis of the Future American Electric Power System," in *IEEE Access*, vol. 9, pp. 68837-68848, 2021, doi: 10.1109/ACCESS.2021.3077856. Available at https://ieeexplore.ieee.org/document/9423995.

Relative to the purchase of output of limited electrical energy producers in intrastate commerce and including qualifying storage systems

1 Definition; Limited Electrical Energy Producers; Limited Producer. Amend RSA 362-A:1-a, III to read as follows:

III. "Limited producer" or "limited electrical energy producer" means a qualifying small power producer***, a qualifying storage system,*** or a qualifying cogenerator, with a [~~total~~] ***maximum rated generating or discharge*** capacity of [~~not more~~] ***less*** than 5 megawatts, ***that does not participate in net energy metering, that is not registered as a generator, asset, or network resource with ISO New England, and does not otherwise participate in any FERC jurisdictional wholesale electricity markets, except as an alternative technology regulation resource (ATRR) to the extent ATRRs are deemed by ISO New England to function as retail or network load reducers for all other ISO New England purposes. Such non-participation in FERC jurisdictional interstate wholesale markets may be achieved by retirement from such markets.***

2 New Paragraph; Definition; Qualifying Storage System. Amend RSA 362-A:1-a by inserting after paragraph IX the following new paragraph:

IX-a. "Qualifying storage system" means an electric energy storage system as defined in RSA 72:84.

3 Limited Electrical Energy Producers Act; Purchase of Output in Intrastate Commerce. RSA 362-A:2-a is repealed and reenacted to read as follows:

362-A:2-a Purchase of Output of Limited Producers in Intrastate Commerce.

I. A limited producer of electrical energy may sell its produced electrical energy to one or more purchasers other than the franchise electric utility. Such purchasers may be any retail electricity customers located within the same New Hampshire electric distribution utility franchise area as where the limited producer is located or any electricity suppliers serving retail load within such area.

II. Intrastate sales of electricity across the distribution grid shall be facilitated and accounted for by competitive electricity suppliers registered with the commission under RSA 374-F:7 or by municipal or county aggregations under RSA 53-E that are load-serving entities.

III. To participate in such intrastate sales of electricity over the distribution grid a limited producer must be equipped with a revenue grade interval meter that can accurately measure hourly exports to the distribution grid and report such meter data for daily load settlement purposes.

IV. The commission shall ***adopt rules pursuant to RSA 541-A to:***

(a) establish procedures to enable limited producers to sell electricity at wholesale within intrastate commerce and at retail, either directly or indirectly through electricity suppliers;

(b) establish such requirements and conditions concerning intrastate sales of electricity pursuant to this section that it deems necessary to avoid substantial risk or uncompensated costs to the electric utility in whose franchise area the sales takes place.

(c) avoid unjust and unreasonable cost shifting transmission rate effects on retail customers arising from avoided transmission cost credits, which may include provisions to reduce, on a prospective basis, the credit for actual avoided transmission charges to some reasonable portion of the value thereof;

(d) provide for filing or reporting on contracts for such intrastate sales to the commission and the distribution utility to which the limited producer is interconnected, including provision for confidential protection of commercially sensitive financial terms of such contracts; and

(e) provide reasonable consumer protections for retail sales of electricity from limited producers, which may include a requirement for prior review and approval of such contracts before they go into effect. If such a contract review is required, the rules shall provide that failure to disapprove such contract within 60 days of its filing with the commission shall constitute approval thereof. Any such contract review shall not require a contested case.

V. The limited producer shall receive credit for actual avoided transmission charges if the intrastate wholesale or retail sale of such electricity reduces the retail load measured at the wholesale meter point between the distribution system under state jurisdiction and transmission facilities under federal jurisdiction such that transmission charges allocated to the distribution utility are reduced from what they otherwise would be absent the electricity exported to the distribution grid by the limited producer during hours of coincident peak on which transmission costs are allocated. Such credit shall be based on measurement of exports to the distribution grid at the retail meter point without additional credit for avoided line and transformation losses between retail meter points and the transmission grid to provide some sharing of the benefit of reduced transmission charges with other ratepayers who do not participate in such intrastate electricity sales by limited producers.

VI. Purchasers of power from limited producers shall pay for the delivery of such power through tariffs, charges, and rates that are generally applicable to the customer's rate class, except for default energy service charges if not applicable and transmission charges as they may be adjusted pursuant to paragraph V.

4 New Section; Electric Renewable Portfolio Standard; Exclusion to Amount of Electricity Supplied. Amend RSA 362-F by inserting after section 3 the following new section:

362-F:3-a Exclusions to the Amount of Electricity Supplied. If a provider of electricity has revenue grade meter data on the quantity of exports to the grid from a qualifying storage system as defined in RSA 362-A:1-a to the extent that it is charged from the grid, such amounts may be deducted from the calculation of electricity supplied by the provider to its end-use customers for the applicable year for purposes of compliance with RSA 362-F:3 as determined and provided for by the commission.

5 Effective Date. Part V of this act shall take effect 60 days after its passage.