BEFORE THE PUBLIC UTILITIES COMMISISON
STATE OF NEW HAMPSHIRE

IR 22-076

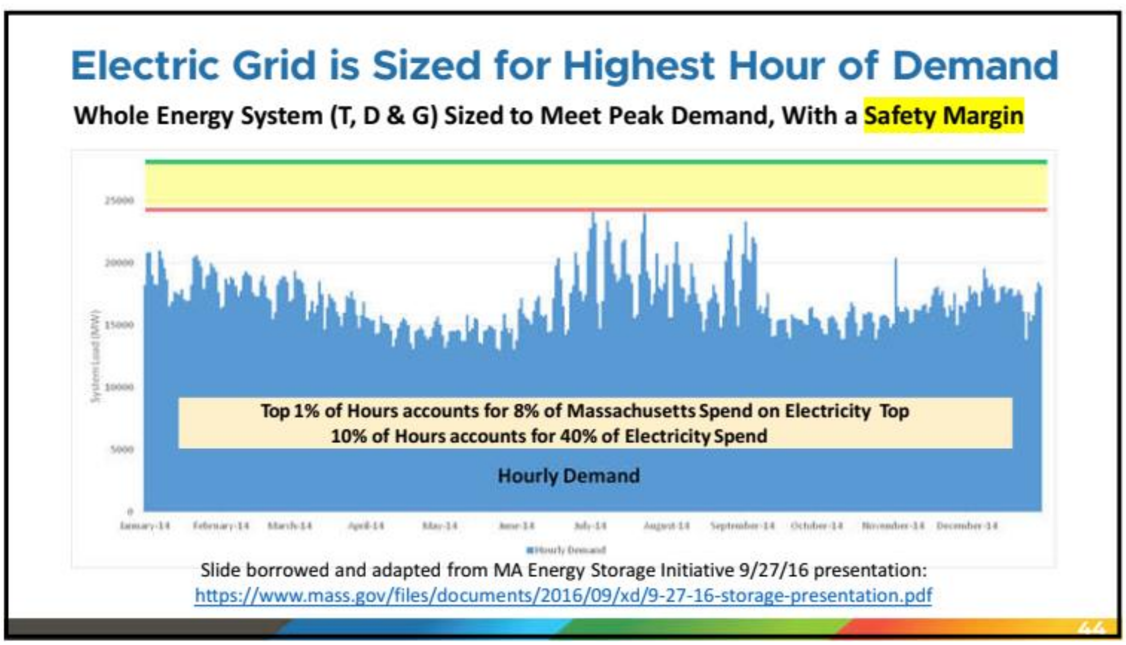
ELECTRIC DISTRIBUTION UTILITIES

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

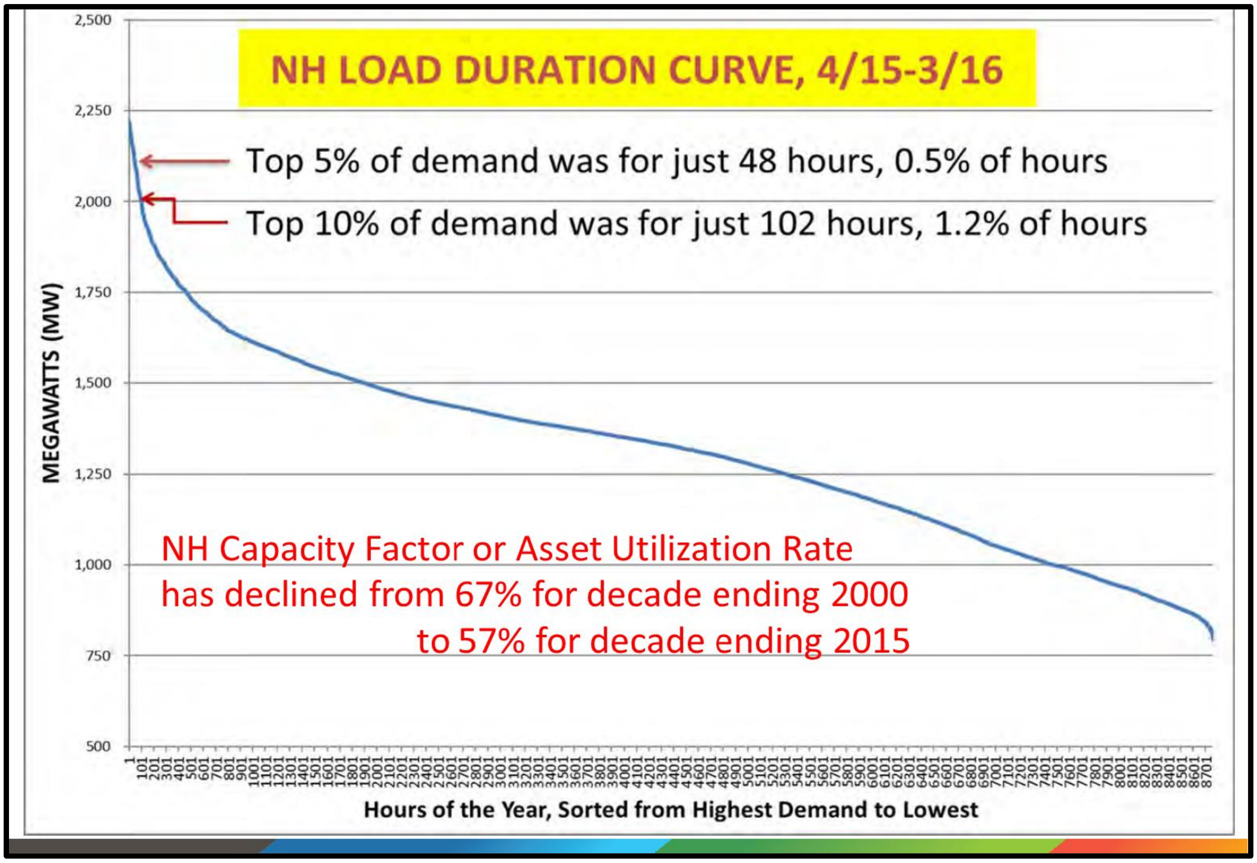
March 21, 2023

COMMUNITY POWER COALITION OF NEW HAMPSHIRE INITIAL COMMENTS

In general, the Community Power Coalition of New Hampshire (CPCNH) finds that the current electric distribution utility (EDU) tariffs are largely and substantially insufficient to support meaningful and cost-effective demand response and are limited in their potential to optimally support greatly expanded electric vehicle charging. There is considerable value to demand response including demand from emerging new flexible electric loads such as vehicle charging and increased use of electric heat pumps for building space conditioning. I like to use 3 slides to illustrate the issue. First is a slide modified from Massachusetts that illustrates how load varies over the course of a year and the fact that the entire electric system needs to be sized to meet the peak coincident demand on each part of the system (T, D, & G), plus a safety margin:



It is important to note that most of the cost of electricity is in the fixed capacity of all these systems. The second graphic that illustrates the opportunity for demand response is a load duration curve that sorts the load for each hour in the year from highest to lowest:



Although the data in this graphic is a bit dated, it illustrates a long-term trend, which is that load factor or asset utilization rates have tended to decline within the region, meaning that the embedded cost of total capacity of the system is being spread over relatively fewer kWh than if asset utilization rates were stable or increasing. Improving the asset utilization rate will tend to lower costs for consumers (while enhancing revenue stability for owners of assets).

A price duration curve looks similar, though stepper on the high end and somewhat flatter on the low load end and is generally correlated with load in a causal relationship that reflects the daily bid stack for bulk generators in the ISO New England interstate wholesale market which starts negative for a few generators for whom it is more expensive to curtail than to pay to keep running, primarily nuclear power and maybe some wind. The prices quickly become positive and gradually increase with load. As load approaches the highest levels each additional increment of generation tends get progressively more expensive.

The significance of this is that shifting an increment of demand away from high load/high cost periods results in a greater reduction in the clearing price for generation than the same amount of load shifted into lower load/price periods of time causes an increase in the clearing price, resulting in cost savings for all customers, while perhaps reducing the frequency of negative pricing for nuclear and wind to the benefit of both supply and demand. Ultimately higher asset utilization rates result in better returns for generators AND lower costs for consumers. Hence the importance of enabling price responsive demand (wholesale and retail transactive energy markets).

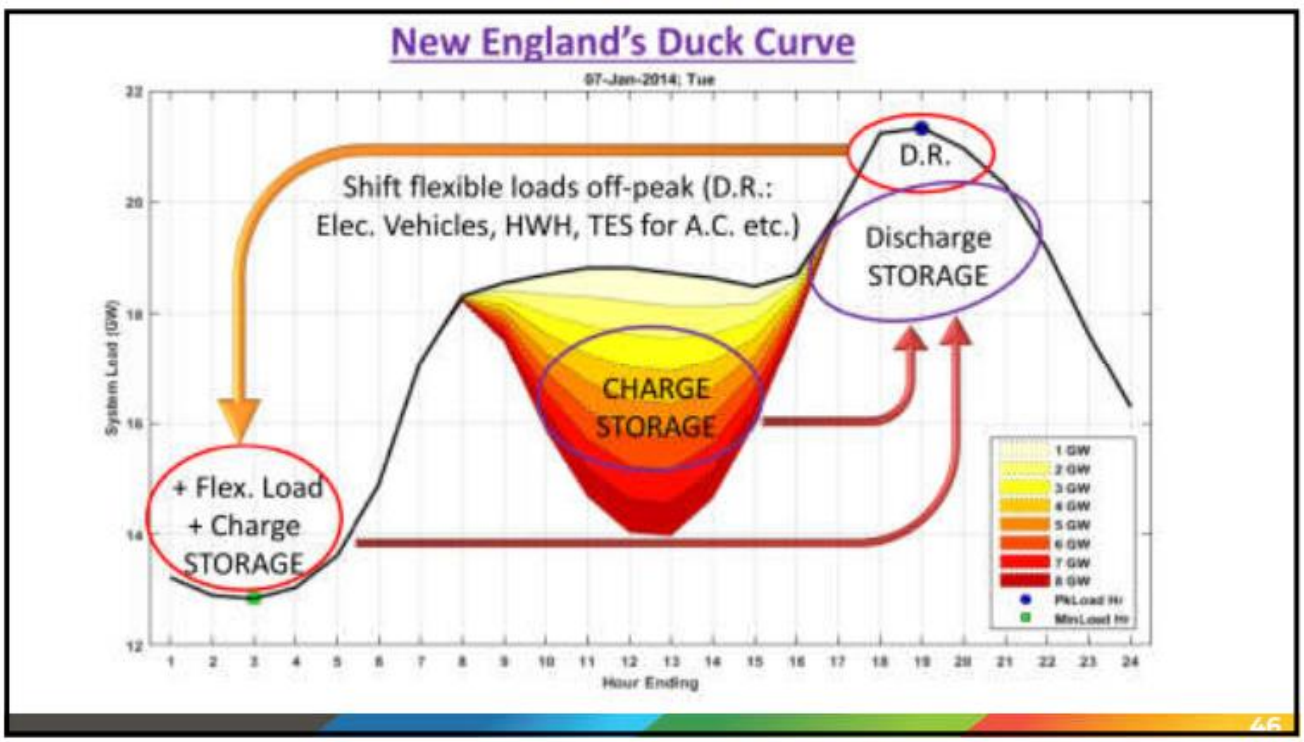
Demand response should be thought of in terms of all distributed energy resources (DERs) to include load, distributed generation (DG) and distributed storage (DS), by which I mean generation and storage smaller than 5 MW, interconnected on the distribution grid, and not a market participant with ISO-NE, which is to say not registered generation or network assets. All types of DERs as defined here function as load reducers for the avoidance of energy, ancillary services, capacity, and transmission costs to the extent they reduce the supply of power delivered over the regional transmission grid at the times those costs are charged to load.

Here in New England the interstate wholesale market is designed to provide strong marginal cost price signals based on temporal or time-varying costs with rates based on cost causation. Generation capacity costs in the forward capacity market are allocated based on load’s share of the single hour of highest demand of the year, the coincident peak demand. Likewise, transmission costs are allocated based on the single hour of coincident peak demand on the transmission system in each month of the year. Both the day ahead and the real time energy markets clear based on the highest (marginal cost) bid in the bid stack that is sufficient to cover the load. These marginal cost price signals, even if to recover sunk costs, are largely lost to retail load and DERs where there is typically little if any access to temporal price signals.

This results is a fundamentally flawed and inefficient market design that is not providing appropriate price signals to load, to demand, to any and all distributed energy resources. A fundamental tenant of well-functioning competitive markets, and well regulated markets that reflect good competitive market behavior to the extent feasible, is that both supply and demand need to be able to respond to the same competitive market price signals. That is when optimal -- or economically efficient -- price formation occurs.

Today, in the real-time electricity market, the price of power changes every 5 minutes and the dispatch of generation is responding to those price changes that are closely correlated to variations in load (though there can be other factors), yet there is very little ability for DERs to respond to hourly price signals, much less at 5-minute intervals. If DERs – demand – that are technically capable of responding to both 5-minute RT prices, as well as day-ahead hourly prices, and hourly coincident peaks, were enabled to do so there could be very substantial economic efficiency gains, appropriate, competitive, and innovative investment in new resources, lower costs for consumers, and more stable returns for investors. This is part of the value proposition the Community Power Coalition wants to bring to its communities.

The opportunity for better enabling demand response is illustrated in this simple graphic of New England's duck curve:



1. How can demand response reduce electricity consumption during periods of unusually high demand, and what rate mechanisms should be developed to compensate ratepayers for their retail electricity market participation?

Demand response can reduce load during high demand by accessing appropriate price signals related to the cost of high demand, such as through time-varying rates (TVR). With technology and communication prices can be provided to devices to automate demand response in many instances. Conventional storage devices such as storage hot water heaters, thermal energy storage for air conditioning loads (usually in the form of ice), and flexible loads such as EV charging, clothes drying, and industrial process loads, like municipal potable water treatment and pumping loads as well as certain wastewater processes such as sediment pumping and dewatering, can be controlled through SCACA systems and commercially available load control technologies, which are increasing being built into appliances, vehicles, and other devices. Consumers and building control system integrators should be able design systems to optimally shift and control loads in response to the value of price signals, such as to reduce capacity tags related to share of annual coincident peak and reduce transmission cost allocation at times of monthly coincident peak demand.

Access to temporal load data through interval metering in utility meters, or in some cases, metering integral to devices, is the key to enabling the development of innovative TVR rate mechanisms. There are numerous ways to design TVR and enable DR, and with access to data, competitive suppliers, community power aggregations, as well as utilities for default rates, and especially transmission and distribution rates, can innovate and compete with different rate and program structures.

2. What standards and systems are needed to enable demand response and a transactive retail electricity market in New Hampshire that includes real-time data transfer?

There are IEC and other standards to support demand response and transactive retail electricity market. Some of these are discussed in the testimony of Dr. Amro Farid on behalf of the Local Government Coalition in DE 19-197, Exhibit 9.[1] I call attention to Bates pages 134-141 for

[1] https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TRANSCRIPTS-OFFICIAL%20EXHIBITS-CLERKS%20REPORT/19-197_2021-05-05_EXH_9.PDF .

overall context and pages 162-163 and slides at 216, 220-221, 224-225, and 248 for more standards specific discussion. Relevant here I would also call attention to the article of "Refocusing on the Consumer" found at Bates pages 253-259.

There is further explanation of these issues in Exhibit 15 in the same docket[2] at pages 12-19 and again I would call attention to the attached article on "Expanding Customer Choices in a Renewable Energy Future" starting at page 44, noting in particular the graphic on p. 48.

For near real time data transfer there are secure cloud-based applications that can stream data out in a single direction through securely accessed APIs, such as ISO-NE does all the time with extensive market and system information, without endangering the source data.

3. Should New Hampshire continue to leverage the current Electronic Data Interchange (EDI) paradigm, or should a new standard be used?

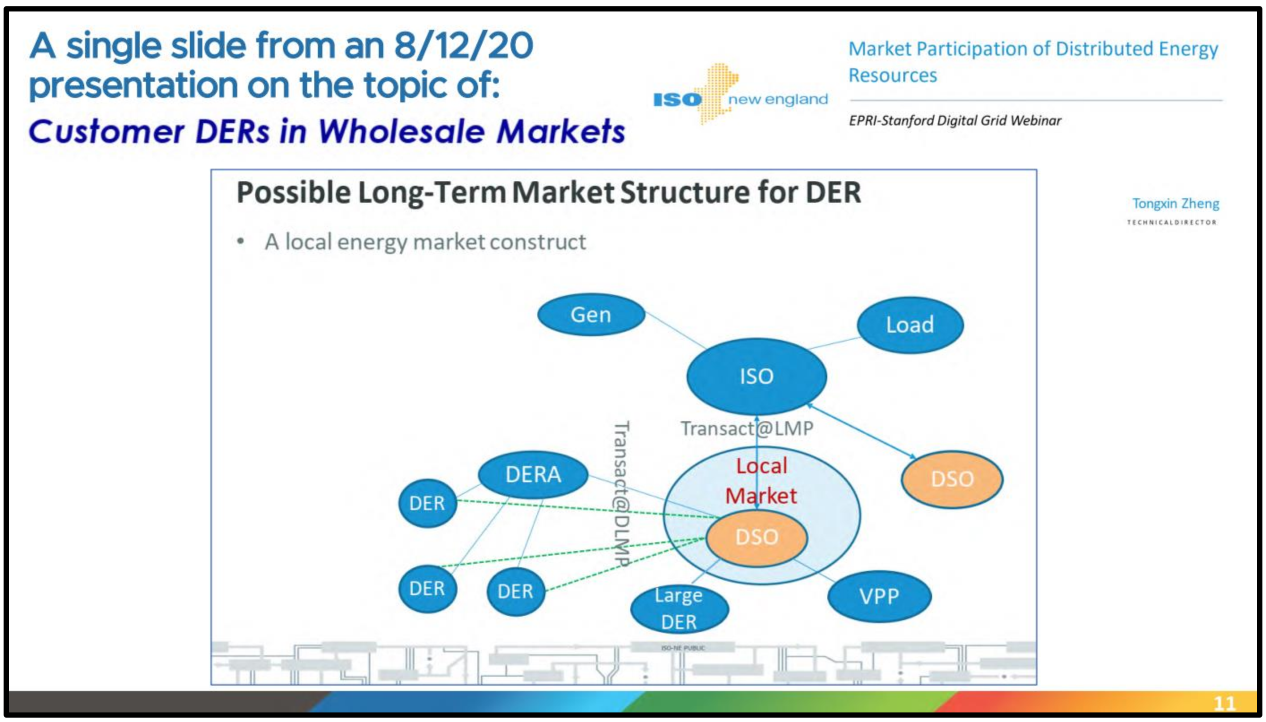
Apparently in other organized markets with competitive electricity supply and customer choice, EDI systems are used to make hourly load data available to competitive suppliers through the 867 data platform, so this seems to be an option. However, EDI is a quarter century or older technology that is very limited in its functionality or adaptability. For example, it requires the supplier to request data for specific accounts and then only returns the 847 or 810 data after some period of time. We have only recently learned that Eversource's EDI system is apparently only capable of 5,000 inquiries per day, and only on business days, so a supplier with tens of thousands of customers, such a community power aggregations (CPAs) may need to parcel out data requests continuously over many days. EDI, by design, is incapable of streaming data in on-going basis. In addition, the legacy data transfer system called VAN is antiquated and expensive (through a 3rd party) and will become increasing so if hourly load data is transferred through this archaic data security system.

Another problem with the current EDI system is that it is apparently not capable of showing negative usage data, in other words, if a customer generator or battery storage device, including vehicle to grid systems, exports power to the grid, instead of showing the quantity as a negative number the EDI system only shows such exports as zero usage. Why the system can't simply

[2] https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TRANSCRIPTS-OFFICIAL%20EXHIBITS-CLERKS%20REPORT/19-197_2021-05-05_EXH_15.PDF

show a negative usage number, or why that is extraordinarily difficult to change is beyond our comprehension. The only place EDUs apparently track negative usage is in their Meter Data Management System (MDMS) and billing system which are apparently not designed to share data with outside parties except through EDI and cannot readily be adapted to do so.

The direct and rebuttal testimony of the Local Government Coalition in DE 19-197 was largely concerned with the idea of developing the state-wide energy data platform as the system to succeed EDI and more expansively be designed to enable secure sharing of meter, customer, market/financial, and system data in support of demand response, integration of DERs, and a retail transactive energy market across New Hampshire that operates in parallel and coordination with the ISO-New England interstate wholesale market, such as is suggested in this slide from ISO-NE:



However, the settlement in that case limited the initial development of the platform to a minimally viable product focusing on the Green Button share my data standard and that does utilize modern APIs capable of streaming data over time. The settlement went beyond just the Green Button standard in two important respects: 1) it is intended in its initial design to be capable of sharing hourly interval load data through APIs, where such data exists, and 2) it is intended to be extensible in its design to add new functionality, such as for some of the use cases described in the City of Lebanon's Scoping Comments at Tab 27[3] and the Local Government Coalition Use Cases Proposals at Tab 34.[4]

4. Do standards exist that enable an interoperable two-way data exchange among the utility, community aggregators, and ratepayers?

The EDI has very limited functionality in this regard. With at least one utility, basic rate data for a 3rd party supplier can't even be entered through the EDI and must instead be separately submitted to the EDU for them to enter. Only the rate selection is entered through EDI.

As noted above the testimony of the Local Government Coalition in DE 19-197 detailed how an interoperable two-way data exchange platform could be developed and the standards to guide such development.

5. How can the EDI standards be updated to enable a transactive retail electricity market in New Hampshire?

It seems very doubtful that EDI can be updated to support a transactive retail electricity market. The City of Lebanon and Town of Hanover, as part of Local Government Coalition in the Data Platform docket argued the need for the multi-use platform to support transactive energy. In lieu of that the Coalition suggests the focus in developing the basic elements of a transactive retail electricity market be to enable the following:

1) Suppliers and customers should have the ability to opt-in to AMI interval metering (Liberty & Eversource) at the incremental cost over the type of new meter the utilities are buying anyways for new and replacement AMR meters, at least to the extend that such upgrades could displace such new purchases that would otherwise occur. This would avoid the problem of stranded costs from Eversource's investment in non-interval AMR meters, but allow early adopters and market innovators to make the case for this option.

[3] https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/LETTERS-MEMOS-TARIFFS/19-197_2020-03-11_COL_SCOPING_COMMENTS.PDF

[4] https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/LETTERS-MEMOS-TARIFFS/19-197_2020-04-03_LGC_USE_CASES_PROPOSALS.PDF

2) Suppliers should have the option to pay for transmission services based on their share of monthly coincident peak for all or a subset of customers consisting of a unique metering subdomain or rate group. DERs that shift load off-peak and/or export power to the grid should be able to get credit for avoided transmission and capacity charges.
3) Utilities should seek to have their load settlement vendors modify their load settlement systems so suppliers can have the option of settling load at 5-minute intervals. When ISO-NE implemented 5-mintue real time pricing and settlement they set it up so load could also be settled at the same 5-minute intervals, if only EDUs were to transmit 5-minute interval data for load settlement, instead of hourly data (most of which is still crudely estimated in New Hampshire).

6. What programs or services are currently offered by the utilities that support customer demand response activities to reduce peak demand, and what are the associated rate mechanisms?

Liberty's battery pilot with it's 3-part time-of-use rates and the corresponding TOU EV rate options are two such programs or services, as are Unitil's TOU rates. Liberty's TOU rate for EV charging is of limited interest to a number of EV owners who also own BTM solar, as the rate is now allowed for the whole house, so people can't use their solar for both the house load and EV charging, so is of limited interest to a big chunk of the potential customer base.

7. What are the relevant Commission decisions, state statutes, and federal laws relating to demand response?

Perhaps the most important state statute in this regard is RSA 374-F that, as the Commission has noted, in RSA 374-F:3 X states with emphasis added: "**Restructuring should be designed to** reduce market barriers to investments in energy efficiency and **provide incentives for appropriate demand-side management** and not reduce cost-effective customer conservation."

Furthermore, the purpose statement provides direction for how that should occur through the provision of appropriate price signals and development of competitive markets at the retail level and not just the wholesale level:

> "Increased customer choice and **the development of competitive** markets for wholesale and **retail electricity services are key elements in a restructured industry** that will

> require unbundling of prices and services and at least functional separation of centralized generation services from transmission and distribution services." (RSA 374-F:1, I)
>
> **"Competitive markets should** provide electricity suppliers with incentives to operate efficiently and cleanly**, open markets for new and improved technologies, provide electricity buyers and sellers with appropriate price signals . . ."** (RSA 374-F:1, II)

RSA 374-F:3, II concerning customer choice also provides that:

> **Customers should be able to choose among options such as** levels of service reliability [which can be achieve through on-site battery storage, with or without DG], **real time pricing**, and generation sources, including interconnected self generation.

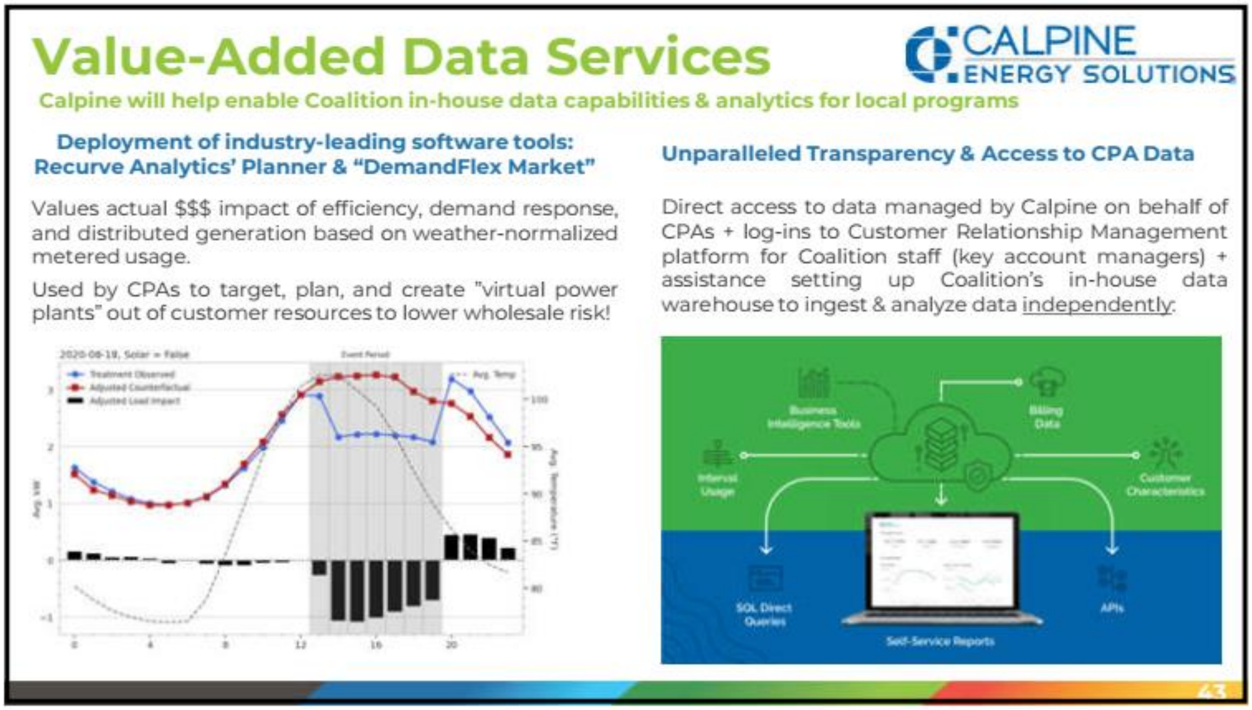
Access to real time pricing, down to 5-minutes intervals, can provide the greatest value to demand response for all DERs capable of responding at such granular intervals, which could include a lot of vehicle-to-grid distributed and automated demand response in coming years.

Relevant Commission decisions include those in DE 06-061[5], Investigation into Implementation of the Energy Policy Act of 2005, including those in Order No. 24,763, Order No. 24,785, and Order No 24,819. Orders in IR 15-296, Investigation into Grid Modernization, are relevant, as are those in DE 17-189, Liberty's Battery and TOU rate docket, as are those in the various EV rate and Unitil TOU rate dockets.

8. What new programs or opportunities could be implemented to further promote demand response practices and reduce consumption during unusually high demand periods?

CPCNH would like to implement Recurve's Demand Flex Market product which one of our vendor partners, Calpine Energy Solutions is contractually prepared to implement for us if we can get the needed interval metering and access to avoided cost values in transmission, energy, and capacity markets:

[5] https://www.puc.nh.gov/Regulatory/Docketbk/2006/06-061.htm



9. What technologies are available today or could be available within a utility's planning horizon to enable support of demand response and transactive energy?

For starters, Eversource and Liberty could enable customers, or their CPA or CEPS on their behalf, to opt-in to AMI and enable near-real time streaming of meter data through a cloud based data collection using existing cellular data networks at low cost. Itron, for instance, whose systems are obviously compatible with Itron MDMSs that Liberty and Eversource use, offers just such a solution[6] that includes enabling the utility to provide permissioned secure API access to meter data in near real time (as frequently as it is collected) to third parties.

10. What market barriers exist that, to date, have prevented greater demand response management?

Retail customers have not had access to appropriate price signals across T, D, & G in the quarter century since NH law has called for such. Competitive suppliers and CPAs are not being given access to fundamental billing determinants that only the EDUs possess, such negative usage data, time-of-use interval usage data, and hourly interval data at reasonable prices. The cost of

[6] https://www.itron.com/na/solutions/use-cases/cloud-based-meter-data-collection

accessing hourly usage data makes access to such data economically infeasible for all but the largest customers.

11. What structural reforms could enable a more competitive retail electricity market in New Hampshire and within ISO-NE?

Implementation and expansion of RSA 362-A:2-b pilots would be one good starting point. Simply enabling “bill” ready use of consolidated billing as required by Puc 2205.16, but not yet implemented by EDUs, to allow a CPA (or potentially other suppliers) to calculate charges or credits for electricity supply and services and provide such charges or credits to the EDU for presentment on the customer’s bill which EDI should be able to support, combined with opt-in access to interval metering, would be a big step forward.

Enabling an option to use coincident peak demand charges instead of customer individual demand for most demand based charges would help, potentially for a number of EV charging use cases as well. Allowing transmission costs to pass through based on share of coincident peak demand would be another significant reform. Allowing DG and DS that can export to the distribution grid at the hour of annual system coincident peak demand to get credit for avoided capacity costs would be another big step forward.

Thank you for the opportunity to share these thoughts.

Community Power Coalition of New Hampshire

by CPCNH Chair Clifton Below