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February 19, 2021

Hon.Michael Vose
Chair, Science, Technology & Energy Committee
New Hampshire House

RE: HB315, relative to the aggregation of electric customers

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

I write to you to express and explain my strong opposition to HB 315 as introduced.

By way of introduction, my name is Dr. Amro M. Farid.

- I'm a resident of Lyme, NH an an Eversource customer.
- I'm an American citizen and vote regularly.
- I am an Associate Professor of Engineering at the Thayer School of Engineering at Dartmouth[1] and an Adjunct Associate Professor of Computer Science at the Department of Computer Science at Dartmouth College. My office is located at 14 Engineering Drive, Hanover, NH. I have taught power systems engineering at the graduate level since 2010.
- I maintain a research expertise in intelligent multi-energy engineering systems which includes power systems engineering, economics, and policy. I have published over 140 peer-reviewed publications in these areas and have been externally funded by ISO New England, the Electric Power Research Institute, the Department of Energy, the Department of Defense, the National Science Founcation, and Mitsubishi Heavy Industries. I have been invited to speak on energy related issues by the International Energy Agency, Hydro-Quebec, the Australian Energy Market Operator, Great River Hydro, the Energy Systems Integration Group, several national laboratories, and a number of prominent universities including MIT, Harvard, Princeton, Stanford and UC Berkeley.
- I am also the Chief Executive Officer of Engineering Systems Analytics (ESA) LLC which is located in Lyme, NH. ESA produces the EPECS (Electric Power Enterprise Control System) Simulation Software that ISO New England uses to conduct its annual renewable energy, energy storage, and demand-side resource integration studies.
- I am the Chair of the IEEE Smart Cities Research & Technical Development Committee[2], Chair of the IEEE Smart Buildings Load and Customers Architecture Subcommitte[3] which

[1] https://engineering.dartmouth.edu/people/faculty/amro-farid
[2] https://smartcities.ieee.org/about/ieee-smart-cities-committees
[3] https://site.ieee.org/pes-sblc/subcommittees/

oversees the IEEE's standard for Blockchain in Energy[4] and Co-Chair of the IEEE Systems, Man & Cybernetics Technical Committee on Intelligent Industrial Systems[5].

- I am a senior member of the IEEE and a member of the ASME and INCOSE.
- I received bachelors and masters degrees in mechanical engineering from MIT and a doctoral degree in engineering from the University of Cambridge, UK.
- I have won a Certificate of Merit for exceptional community service from the United States Congress.

In brief, RSA 53-E, as currently enacted, is a very good law that demonstrates effective bipartisan compromise.

1. It emphasizes economic benefits through ***market competition***.
2. It emphasizes New Hampshire's long-term prosperity through ***systemic innovation***.
3. Its implementation is ***technically feasible*** using today's technology.
4. It does not compromise ***reliable and secure grid operation***.
5. It opens the door to a ***Shared Integrated Grid*** that can deliver quantifiable synergistic benefits through real-time pricing transactive energy mechanisms.

Like all good laws, it is not without points for improvement. However, we cannot make the perfect be the enemy of the very good; especially when the proposed HB315 is vastly inferior in all five respects outlined above. The remainder of my testimony elaborates on these five points.

I. HB315 Inhibits Market Competition

My opposition to HB315 stems from the degree to which it appears entirely inconsistent with the spirit of market competition engrained in New Hampshire's laws; including its constitution, RSA 374-F and RSA 53:E. The NH Constitution at Part II, Article 83 limits and regulates the power of monopolies:

> *". . . all just power possessed by the state is hereby granted to the general court to enact laws to prevent the operations within the state of all persons and associations, and all trusts and corporations, foreign or domestic, and the officers thereof, who endeavor to raise the price of any article of commerce or to destroy free and fair competition in the trades and industries through combination, conspiracy, monopoly, or any other unfair means; [and] to control and regulate the acts of all such" entities.*

As I elaborate later, the language of HB315 does not support the stated purpose of RSA:53:E and instead dilutes its legislative effect. The original purpose of RSA 53:E is stated below:

> *"The general court finds it to be in the public interest to allow municipalities to aggregate retail electric customers, as necessary, to provide such customers access to competitive markets for supplies of electricity and related energy services. The general court finds that aggregation may provide small customers with similar*

[4] https://standards.ieee.org/project/2418_5.html
[5] https://sites.google.com/view/ieee-smc-tc-iis/

> *opportunities to those available to larger customers in obtaining lower electric costs, reliable service, and secure energy supplies. The purpose of aggregation shall be to encourage voluntary, cost effective and innovative solutions to local needs with careful consideration of local conditions and opportunities."*

Furthermore RSA 374-F states:

> *" The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. 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. ...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, and improve public confidence in the electric utility industry."*

These legal clauses provide motivation for supporting and developing competitive markets in New Hampshire. Therefore, my first and primary critique of HB315 is that it inhibits market competition. To elaborate, I refer to Attachment A in the testimony provided by Assistant City Mayor of Lebanon Clifton Below.

p.1, §1, lines 1-4; **A1** (p.1, lines 14 & 31) strikes the words "provide" and "electric power supply" from the definition of aggregation. Community Power Aggregators (CPAs) are likely to have within their jurisdiction distributed generation assests that do not qualify for direct participation in the wholesale ISO New England market. These may be conventionally-fired municipal generation assets or solar photovoltaic generation assets. Similarly, as CPAs become more sophisticated in their provision of electricity supply, they may develop the capacity to use their municipal load-consuming assets as "*virtual power plants*" that provide kilo-watt-hour (kWh) equivalent electric power supply. Although these electricity supply options are likely to be very cost effective on a kWh basis, HB315 seeks to prohibit these scenarios rather than enhance market competition through an expanded supply portfolio.

p.1, §3, lines 9-20; **A3** (p.1, lines 31-36) prohibits CPAs from providing any demand side management, conservation, or energy efficiency service that are not directly administered through a distribution utility or regional system operator. This statement should strike any neutral observer as 1.) limiting the services that a CPA can provide and 2.) making them perpertually subservient to distribution utilities; both to the detriment of electricity market competition and the stated purpose of RSA 53:E. From a common sense perspective, electricity customers do not need permission from grid operators to turn off their own lights when they leave a room, or turn down

their heat pumps before they go to sleep, so why do CPAs need permission to help customers make these decisions? Furthermore, none of these services are natural monopoly functions nor do they pose a plausible risk to grid operation and in my opinion are sufficient reason to oppose HB315.

p.1, §3, lines 16-17; **A4-A6** (p.1, lines 37-39), similarly, prohibits CPA from meter reading, customer service, and other energy related services. Again, it is difficult to understand how the authors of HB315 seek to achieve greater market competition with limited service offerings. It is well-established in energy economics that market competition grows with more service offerings rather than less. Again, an ordinary electricity customer can go on Amazon.com today and purchase a revenue-grade energy meter and hire a qualified electrician to install it in their electrical panel. So why is it that a CPA can not provide the same product? Or bundle data-centric services with the energy-meter product? It is no secret that many of New Hampshire's investor owned utilities have not invested in "smart meters" (e.g. AMI) that provide a value of electric power consumed as a function of time. In my case, as an Eversource rate payer, I have had to invest several hundred dollars of my own money to buy such an energy meter. Had their been a CPA in Lyme, I would have entertained a meter-reading service from a CPA as a means of making informed real-time decisions about my energy consumption as I now do with my own off-the-shelf energy monitor. Such a meter-reading service would have been even more attractive if the CPA bundled it in with their electricity supply service and not forced to me to buy it out-of-pocket as I have had to do as an existing Eversource customer. This example is exactly the type of real-life market competition that our electric grid needs and that RSA 53:E purposefully intends.

p.1, §3, lines 16-17; **A4-A6** (p.1, lines 37-39), also prohibits "customer service" and "other related services". Speaking as a small business owner, I'd like to kindly ask the authors of HB315 to go up to any small-business-owner in New Hampshire and tell them that there will be a new law that prohibits their business from providing customer service and instead it will be offered by a much larger competitor. I'm sure that we would hear a diversity of "colorful" responses for the simple reason that customer service is integral to the success of any delivered service; be it from a for-profit business, non-for-profit business, CPA or otherwise. Furthermore, the presence of the clause "other related services" in RSA 53-E is an open-ended invitation to spur market competition as is intended by the statute. The prohibition of "other related services" is just a blatant attempt to stifle the potential for any further developments of a competitive electricity market that were not prohibited earlier in the clause.

§5, p.2, lines 4-8; **A9-A10 (**p.2, lines 29-33) prohibits the CPA from serving as a load serving entity (LSE). Again, the proposed language in HB315 is clearly against market competition. Retail customers, businesses, and municipalities can and do act as LSEs today in ISO New England's wholesale electricity markets. I do not see how a law intended to expand market competition would specifically prohibit one type of entity from serving as a LSE, but allows others. If a municipality that has already registered as an LSE becomes a CPA would it need to withdraw its registration? I think it is plain to see that such an action reduces market competition.

§5, p.2, lines 18; **A11 (**p.2, lines 43-44, p.3, lines 1-5) further blocks CPAs from negotiating with utilities to provide access to interval metering data. I have already spoken to my actions as an Eversource customer to install my own energy monitor in my home's electrical panel. However,

such data is not just valuable to the individual homeowner, it is also critical to the development of new ***transactive energy services*** based upon ***real-time pricing***. As is well-known in economics, the availability of data is the basis for competitive, market-based ***innovation***. I will return to subjects of innovation and transactive energy later in my testimony. For now, it is unclear why HB315 would seek to eliminate this clause when the intended purpose of RSA 53:E is to spur market competition.

§5, p.2, lines 18; **A12** (p.3, lines 6-8) is a further limitation on the CPA's access to data; this time through the Electronic Data Interchange (EDI) to which all competitive electricity suppliers (CES) currently have access. Again, I don't see why RSA 53:E that is intended to achieve market competition would be well served by HB315 that would make EDI data available to some competitors and then withhold this same data from others. Such an amendment is clearly against competitive market principles.

§5, p.2, line 18; **A13 (**p.3, lines 11-13), similarly, prohibits CPA's access to individual customer for the research and development of new energy services. Again, if the purpose of RSA 53:E is to develop a competitive electricity market, then why would we introduce HB315 with clauses that directly impede their access to customer data and their ability to research, develop, and innovate? I do not see any strong rationale for this in electric power systems economics and engineering. Furthermore, as an academic with a vibrant research program, I can personally attest to the benefits of research and development activities in the State of New Hampshire; particularly as municipalities partner with leading universities like Dartmouth and UNH. I will return to this subject in the following section of my testimony.

II. HB315 Inhibits Systemic Innovation

In addition to inhibiting competition in retail electricity markets, HB315 also impedes systemic innovation in the modernization of the electric power grid and in the New Hampshire economy more broadly. The modernization of the electric power grid is not just the introduction of new technologies like smart meters, distributed automation, and solar panels. It also comes with commensurate changes in market design, regulations, and energy policy.

From an economic perspective, the most economically efficient grid does two things. 1.) It sends to consumers monetary signals of the scarcity of electrical supply. 2.) It sends to suppliers monetary signals of the availability of demand. Because electricity demand and electricity supply (especially in the presence of wind and solar generation) are time-varying, then the most efficient prices are time varying as well. Such highly efficient, time-varying rates are the norm in wholesale electricity markets like ISO New England. In contrast, the typical (default) retail electricity rate is quite static as we generally experience from our monthly residential electricity bill. Nevertheless, such static rates create all sorts of market inefficiencies because electricity prices do not reflect the balance of supply and demand. To eliminate economic efficiencies, innovations in electricity market design and regulations are required.

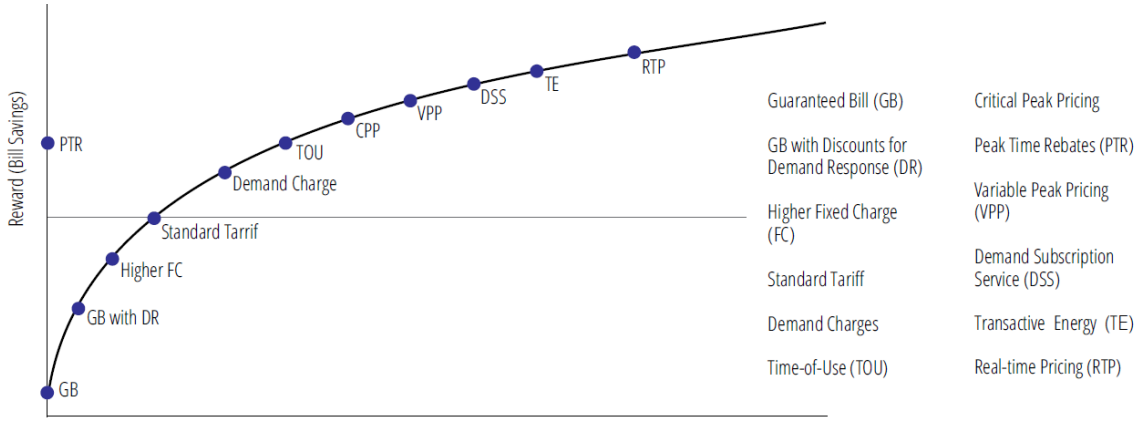

Figure 1. The Efficient Rate Frontier -- Systemic Electric Policy Innovations

One way to characterize these innovations is the efficient rate frontier shown above in Figure 1. The standard static electricity tariff serves as a baseline of sorts. In the meantime, real-time pricing based upon a ***transactive energy*** service sits all the way on the right as the most advanced but also much more economically efficient pricing approach. What is transactive energy? It is a system of market-based 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. It's a technical term that applies to the regional interstate bulk electricity market and transmission grid that ISO New England operations. Given the current reliance on fixed rates, it does not (yet) apply to the retail electricity market and distribution grid although we have the technological means to do so through real-time pricing mechanisms. Between the standard static electricity tariff and real-time pricing based upon transactive energy service, there are a number of different options. It is in this choice that community power aggregators, or community ***choice*** aggregators as they are called in other states, have the potential to offer multiple electricity pricing schemes to New Hampshire residents based upon their preferences. As the New Hampshire resident opts towards more dynamic, even real-time pricing, the more likely that they will see economic savings on their bill. The more static their electricity rate is, the more the tariff includes a premium that is ultimately reflected in higher monthly electricity bills. Everyone is different and electricity markets should be designed to reflect the plurality of its people. The choice of electricity tariff should be left to New Hampshire's residents. Community power aggregators as they are described in RSA 53:E have the potential to greatly expand these choices. Unfortunately, the propsed HB315 severely restricts the types of electricity services that NH residents will be able to choose from.

Systemic innovation in our electric power grid's market structure also has the potential to grow our state's economy. I'd like to offer several examples. To start, the enactment of RSA 53:E in 2019 immediately attracted the interest of "community power brokers" such as NH's home grown Freedom Energy Logistics and Standard Power, along with brokers and suppliers with experience in offering competitive, though usually static, electricity rates in other states. Their presence promises to bring new services to the state's smaller electric customers, reduce electricity bills for everyday New Hampshire residents, and grow the economy through greater market competition.

Similarly, a number of demand response companies (e.g. CPower,) are taking advantage of demand response innovations in the wholesale electricity markets to provide financial benefits to

businesses and municipalities across the state. These cost savings translate to more vibrant businesses. They also translate to municipal budgets as savings to taxpayers and water & sewer utility ratepayers. Such competitive services in the electric power grid, however, are just the beginning in New Hampshire's path along the efficient rate frontier. A new regulatory innovation like 53-E with robust and diverse provisions for CPAs to compete can further advance New Hampshire's economy beyond the relatively modest services on the market today.

Consider the very end of the efficient rate frontier in Figure 1. At this very moment, the United States Department of Energy Building Technologies Office, Solar Energy Technologies Office, Vehicle Technologies Office and the Office of Electricity have released a Funding Opportunity Announcement (FOA) for R&D proposals on "Connected Communities"[6]. Winning projects will be awarded between $3-7M. Upon reading the FOA, one finds that it specifically includes the development of transactive energy services based upon real-time pricing. It also emphasizes the effective collaboration of "connected communities" with local distribution utilities. RSA 53:E, through its existing provisions for CPA, only enhances the potential for such collaborations between CPA and distribution utilities. Innovations in policy and regulations make New Hampshire much more attractive for federally funded projects.

The DOE Connected Communities FOA is not the only such opportunity. In 2019, the Thayer School of Engineering, partnered with the City of Lebanon and Liberty Utilities to study transactive energy services within the city. Liberty Utilities graciously shared load and system data. The City of Lebanon and the Thayer School of Engineering handled this data with the due care that it deserves. Most of all, the work fomented a healthy dialogue on community power aggregators, transactive energy services and real-time pricing. The work led to several peer-reviewed publications in leading conferences and journals which I attach at the end of my testimony as evidence of innovation in action [Attachment 1-3]. In his recent letter to you and this committee, Gov. Sununu wrote: "*The key for the long-term success of community aggregation will be stakeholders engaging in constructive dialogue to reach achievable policy goals".* The evidence shows that the healthy dialogue exists and is already bearing fruit.

Such collaborations between people and institutions, once initiated, often grow to bring long-term benefits. At this very moment, the Thayer School of Engineering at Dartmouth is collaborating with the Tuck School of Business at Dartmouth, MIT, UNH, the City of Lebanon and Liberty Utilities to propose a $2.5M CPA-based, real-time pricing, transactive energy service project to the National Science Foundation's Smart and Connected Communities program[7]. When federal R&D funding come into the state, it has immediate economic benefits. It creates new R&D jobs, and it supports our public and private institutions for higher education. It also showcases New Hampshire as an "innovative state" that is driving exemplary technical and economic progress. Even if this project is not awarded – this time – the benefits are already realized. The multi-university collaborative links are already established and have value. The cooperation between academia and a local municipality is already established and has value. The cooperation between a municipality interested in community power aggregation and a distribution utility is already established and has value. And there will be other opportunities to seek out federal funding for

[6] https://www.energy.gov/eere/solar/funding-opportunity-announcement-connected-communities
[7] https://www.nsf.gov/pubs/2021/nsf21535/nsf21535.htm

this type of techno-economic multilateral cooperation. RSA 53:E in its current form, without dilution by the proposed HB315, supports market-based competition and innovation.

III. The Enacted RSA 53-E is Technically Feasible

Such "fancy" R&D initiatives should not in anyway lead us to believe that community power aggregators are unattainable "rocket-science". Without qualification, we have the technical werewithall to setup effective Community Power Aggregators in the state today.

In his recent letter, Gov. Sununu says: "*Unfortunately, unanticipated complications and technical uncertainties have kept this policy change from moving forward as quickly as it should.*" In some cases, I have attended some of the discussions related to the implementation of RSA 53-E and in others I have been briefed by colleagues that have attended. In my opinion, the "*unanticipated complicated and technical uncertainties*" center around the question of what, how and when data is exchanged between a distribution utility and a CPA. These questions, in turn, strike me as business negotiations rather than any veritable frontier of technical feasibility.

Let's look at this simply. Community Power Aggregators have been around a long time. Nearly a dozen states have CPA laws, and many of those have been successfully implemented some form of CPA. In some states, the CPAs have been more successful than others. And some states have allowed CPAs to do more than others. But nevertheless, the data exchange and information technologies to stand them up has been verified and is available domestically. To argue that CPAs are technically infeasible in New Hampshire when there is overwhelming evidence that they are feasible in other states is equivalent to saying that the distribution utilities and CPAs in New Hampshire are somehow technically inferior. We all know such a presumption to be false. New Hampshire's distribution utiltiies operate fine in other jurisdictions and the individuals involved in forming CPAs in New Hampshire are recognized energy experts outside the state.

So let's call the "*unanticipated complications*" for what they are: real-life business negotiations in an emerging competitive marketplace. The fact of the matter is that the what, how and when data gets exchanged has practical dollar-and-cents implications for both sides. Access to data is equivalent to market competitiveness. Furthermore, we have a retail electricity marketplace that is largely monopolistic transitioning to something that is much more multilateral. For both of these reasons, it shouldn't surprise us that there will be wrangling. It also should not surprise us when each side presents their best arguments to support their side; even if it involves red-herrings like the technical infeasibility of data exchange. As I have found so many times in my career, it's amazing how fast something can become technically infeasible when it doesn't support management's objectives.

One particular red-herring that has surfaced as a part of the implementation of RSA 53-E has been the exchange of power system data. It's a red-herring for the simple reason that there is no mention of system data in RSA 53-E. Furthermore, it is not a prerequisite to standing up a CPA because other CPAs have been implemented before without system data. So the exchange of system data should not be used as a reason to derail CPA implementation. Nor should it be a reason to support HB315 either.

So that my testimony is neither misunderstood nor misconstrued, *I firmly believe that the judicious exchange of system data with relevant grid stakeholders is beneficial for the power grid*. Even though system data is potentially sensitive, there are many precedents where system data has been transferred beyond the transmission and distribution utility under well-defined rules, monitoring, and governance. Consequently, it is insufficient to use the fact that this data is sensitive as a single means of precluding it from being shared with other relevant grid stakeholders. Leading distribution utilities like National Grid (MA,NY) and Con Edison (NY) have created web portals with relevant system data that can be used to understand relevant questions like solar photovoltaic hosting capacity. National Grid's Massachusetts portal is found at https://ngrid.apps.esri.com/NGSysDataPortal/MA/index.html. They have similar portals for Rhode Island and New York. Figure 2 shows GIS maps depicting National Grid's feeders in Massachusetts. Con Edison's portal is found at: https://www.coned.com/en/business-partners/hosting-capacity. Figure 3 shows GIS maps depicting Con Edison's feeders in New York. We actively use this data in the Dartmouth-LIINES to research and develop innovative data-centric products. Even Eversource in Connecticut provides access to an ESRI GIS layer[8], with an array of base map options and full zoom capability, for looking at hosting capacity as shown in Figure 4 below. Despite this fact, Eversource Lobbyist Donna Gamache has testified: "*... [There are] claims that communities who undertake community power plans should or must have a view of our distribution grid ... into the distribution grid. Let me be clear, there is nothing on the shelf that would enable this and therefore no idea on the overall cost and who would pay for this.*"

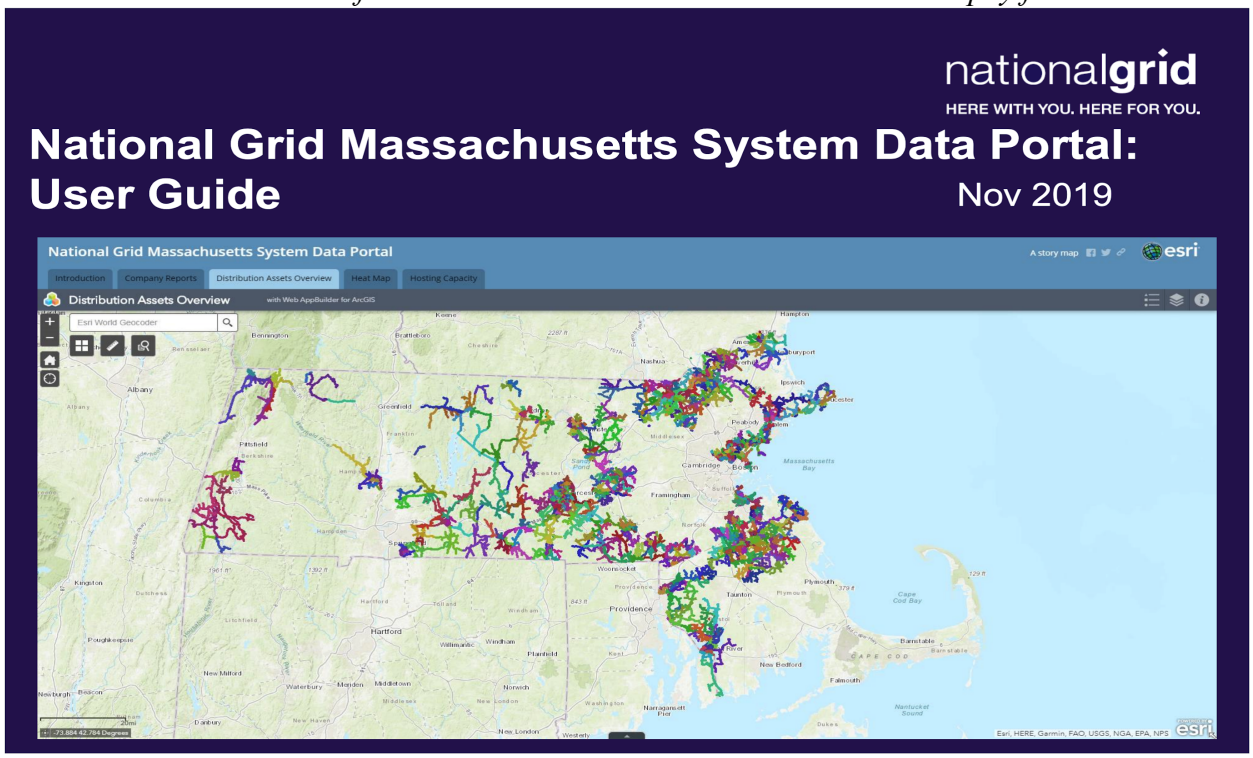

Figure 2. A Screenshot from the National Grid Massachusetts Portal Depicting Distribution System Feeder Data

[8] https://eversource.maps.arcgis.com/apps/webappviewer/index.html?id=4a8523bc4d454ddaa5c1e3f9428d8d8f

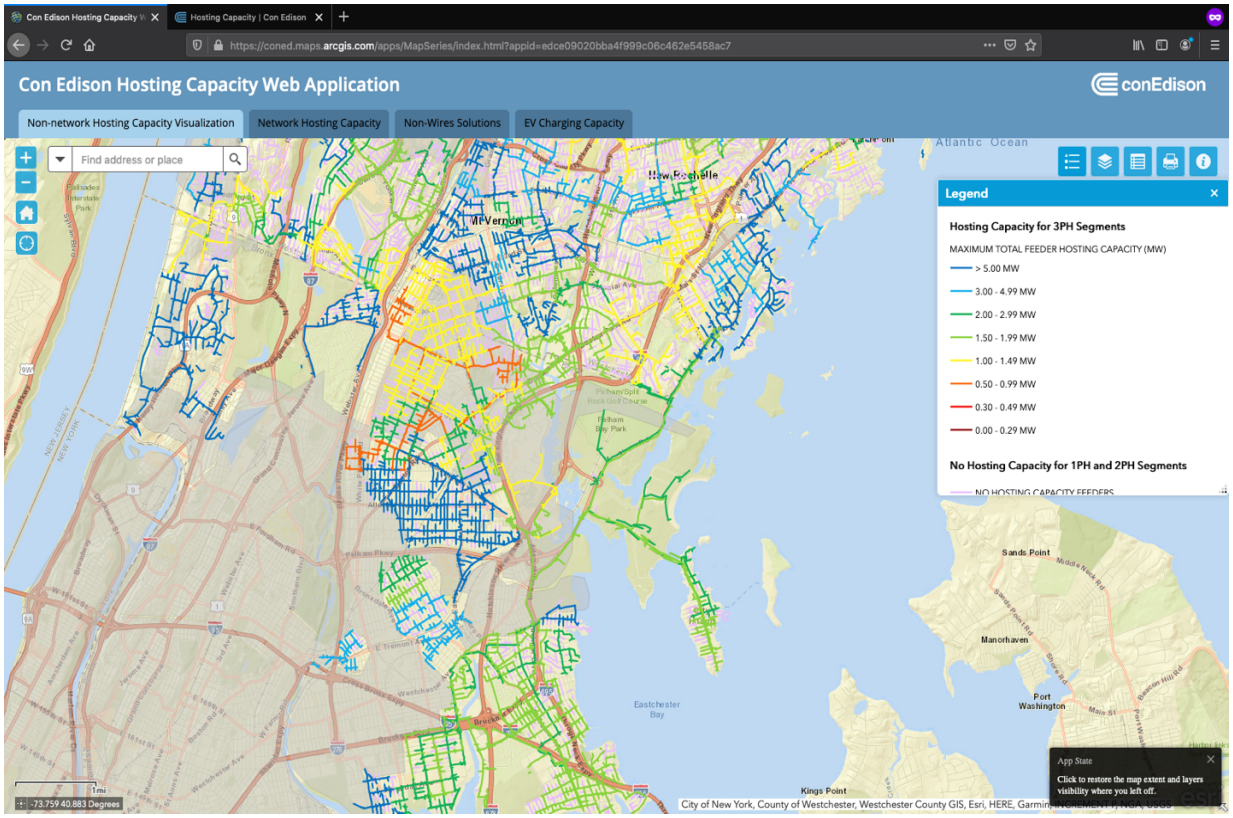

Figure 3. A Screenshot from the Con Edison New York Portal Depicting Distribution System Feeder Data

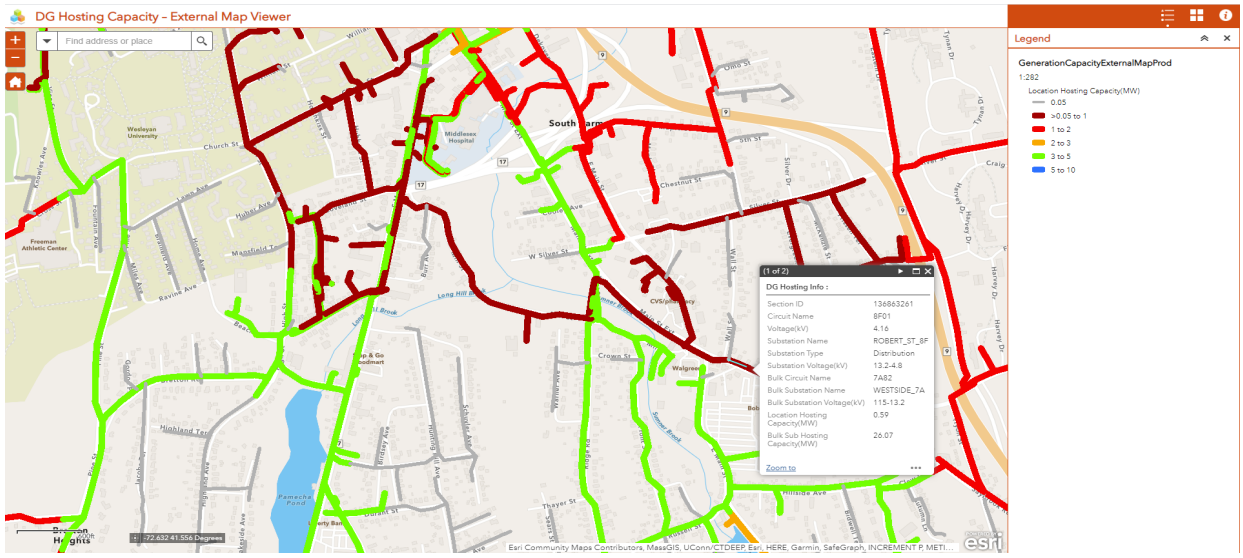

Figure 4. A Screenshot from the Eversource CT Hosting Capacity ArcGIS Map Viewer zoomed to Middletown CT

Furthermore, our research collaboration at the Thayer School of Engineering at Dartmouth involved the exchange of system data from Liberty Utilities. Beyond these immediate precedents, we need to understand that utilities exchange extensive amounts of system data in near real-time with wholesale market operators like ISO New England everyday. This exchange of system data

is used by both parties to ***collaboratively*** provide reliable, secure, and cost-effective service. Many of my ISO colleagues have relayed stories where a control room operator at an ISO calls a control room operator at a utility to ask "Are you seeing what I'm seeing?" And then they work it out. When it comes to reliable, secure, and cost-effective service, there is absolutely no reason to believe that such a ***collaborative environment*** between CPAs and utilities would not emerge. In my opinion, such a collaborative environment would emerge and it would be beneficial to all grid stakeholders and New Hampshire as a whole.

IV. The Enacted RSA 53-E Does Not Compromise Reliable & Secure Grid Operation

Unfortunately, the topic of exchanging system data with CPAs has not only been used to derail CPAs and support HB315, but it has also been used to insinuate that it would compromise the reliable and secure operation of the grid. For example, Eversource Lobbyist Donna Gamache in her testimony to this committee asked: *"How would these communities ensure security of the grid?"* I feel obliged to reject the premise of the question because it contains a logical fallacy that the exchange of system data in terms of a "view into the distribution grid" is equivalent to "ensuring the security of the grid". Utilities do need to see their own grid to secure it, but having "a view of the grid" does not mean that one must secure it! Gamache continued in the same testimony to say: "*Every single week, we receive more than 1 million hits on our system, mainly by bad characters and other countries to shut down our system.*" While I can not independently verify this number, there is a consensus in the electric power systems and cyber-security literature that protecting the grid from cyber-attacks from "bad characters and other countries" should neither be neglected nor underestimated. Nevertheless, and for many reasons, the statement is a remarkable red-herring that plays on the fears of NH residents.

- Utilities are responsible for securing their own grid assets, not CPAs.
- Exchanging system data with CPAs does not somehow absolve the utility from securing its own grid assets, nor does it imply that CPAs must now take on a new role of securing the grid.
- Securing the grid is entirely distinct from securing system data about the grid.
- Receving system data is not required to implement a CPA.
- RSA 53-E makes no mention of system data.
- Therefore, arguments about the cyber-security of exchanging system data do not support HB315 as a means of amending RSA 53-E.
- Finally, system data is exchanged today securely by leading utilities including Eversource.

Ultimately, we have the technology today to support the wide range of innovation that RSA 53-E enables without compromising the reliable and secure operation of the grid. This includes real-time pricing and transactive energy services deployed in an opt-in pilot or made available to early adopter NH residents.

V. The Enacted RSA 53-E Enables a Shared Integrated Grid

Thus far, my testimony has argued against HB315 because it impedes market competition and systemic innovation. My testimony has also argued for RSA 53-E because it is technical feasible and does not compromise the reliable and secure operation of the grid. However, I must go further.

RSA 53-E enables a ***Shared Integrated Grid***. The term Shared Integrated Grid has been developed by the Electric Power Research Institute (EPRI) as the leading institution of electric industry research & development in the United States. To be clear, this is a concept developed by leading electric utilities and has the support of leading electric power systems engineering academics now as well. Since 2017, the Thayer School of Engineering at Dartmouth has been working with EPRI to advance the Shared Integrated Grid through multiple collaborative projects.

Concretely speaking, a shared integrated grid consists 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. The first of these is equivalently called the "energy Internet of Things". The second of these is often referred to as transactive energy services as previously defined. In the New Hampshire context, the third of these is most easily understood as community power aggregations (CPAs). Our recent open-access book, eIoT: The Development of the Energy Internet of Things in Energy Infrastructure, commissioned by EPRI (https://www.springer.com/gp/book/9783030104269) explains how these three elements combine to create a shared integrated grid. I have also presented on the topic of the Shared Integrated Grid, the energy Internet of Things, and eIoT information standards at a recent workshop hosted by EPRI and Stanford University. See attached slides [Attachment 4].

Mike Howard President and CEO of EPRI describes the shared integrated grid in his September 2018 article in the EPRI Journal (https://eprijournal.com/welcome-to-the-new-world-of-the-interactive-energy-customer/). On the same page, hyperlinked below is a video that explains the shared integrated grid (Shared Integrated Grid by EPRI: https://youtu.be/PknNL0TnCxQ). Though the video is worth watching for the graphics, for convenience, it is transcribed here: "*Imagine an energy future when smart appliances, water heaters, thermostats energy, storage, electric vehicle chargers, and rooftop solar are more than customers assets. They are energy solutions integrated with electric grid planning and operation that can enhance resiliency and provide value to customers at all levels of the grid, creating a shared integrated grid. Much like the mobile apps that make subletting an apartment today easier than ever before, network operators can seamlessly enable a shared integrated grid by introducing a platform to better utilize shared energy resources. By connecting to this platform through an app many different businesses can offer shared energy solutions for customers enabling next-generation demand response, more efficient use of grid assets, more robust ancillary services, and improved hosting capacity to support more electric vehicles and solar PV on the grid. Smart water heaters that work hardest when electricity demand or prices are low, thermostats that enable network operators to reduce peak demand and operate distribution assets more efficiently, and customer-owned chargers that fuel electric vehicles with the capability to shift charging to times of excess generation capacity.*"

"In this future, grid investments can expand to include acquiring grid services from customers' assets. Transmission and distribution companies can harness these emerging technologies which provide customer energy solutions and grid support. Participating customers can receive incentives to share their resources for grid support, and society can benefit through a lower overall cost for all customers. Realizing this vision requires a platform that fully integrates grid planning and operation with those distributed energy resources that customers have opted in to share with

the grid. In addition to buying a water heater from a store or website, a customer can purchase it from any qualifying solution provider through a shared integrated grid e-commerce platform, by logging into an app that is integrated with the network operations and planning system, and with one simple click selecting a smart water heater to be installed by a trusted service provider, with incentives based on the customers' needs and the value to the grid. For customers, the app can provide customized alerts over the life of an appliance identifying service needs and offering energy-saving tips. For network operators, the same platform serves as a standard interface connecting the asset to utility planning systems and distribution operation systems and linking to aggregated services for the bulk power system, through secure interfaces enabling real-time operation and planning, with a customer-owned asset like a water heater treated as a wire's asset for the purpose of grid investment planning. The result: a connected device such as a water heater can then optimize energy use based on grid needs shifting from heating water as needed over the course of the day to working at times when energy demand is low and limiting use when demand is high, all without impacting the customer's comfort."

"Through this approach, the definition of transmission and distribution investments expands to include grid services delivering greater value to customers and all levels of the grid. Connected technologies can create a shared integrated grid, a new e-commerce reality, and a win-win situation for network operators and every customer; a cost-effective approach that enables better-informed resource planning and strategic capital investments at the individual customer level; unlocking better service quality, improving the customer experience, and providing greater value by integrating resources from the customer's home to the community and the grid as a whole. The shared integrated grid, a key component of the integrated energy network can provide for clean cost-effective electricity with greater customer choice, comfort, convenience, and control The Electric Power Research Institute is leading collaboration with industry and other stakeholders to enable this customer-focused energy future."

Another video on the same page explains the role of the interactive energy customer in the shared integrated grid (The Interactive Energy Customer by EPRI: https://youtu.be/-hpxUymaR48. See also The Six Cs by EPRI: https://youtu.be/15A8WKFXt1k). For convenience, it is transcribed here: *"The grid that has served electric utility customers well for more than a century is changing, adapting to new demands, and evolving to meet new expectations. Originally designed for one-way service the grid has become an integrated energy network, an enabler of new technologies that provide greater customer choice and enhanced service reliability and affordability. In an era of e-commerce enabled by mobile apps increasingly connected customers expect streamlined access to products and services that align with their lifestyle. A convergence of new technologies and rising customer expectations presents forward-thinking utilities greater opportunities to connect with customers, when and how they want to become more than an energy provider: an energy partner, making a better quality of life possible for all. The interactive energy customer is central to a shared integrated grid, one that redefines utility capital investments by encouraging customer-specific improvements that deliver value to all, empowering customers to make better energy management decisions, enabling utilities to better draw from customer-owned resources, to actively manage today's resources and better plan for the future, enhancing cybersecurity to securely manage the data, making this new utility reality possible and encouraging efficient electrification to make the most of our natural resources while delivering reliable, safe, affordable,*

and cleaner energy. The technology to enable this energy future already exists, customers are ready for the change, forward-thinking utilities can take a bold step forward by embracing new and emerging technologies to expand their energy service capabilities, enhance service quality, drive greater value, and better engage with the interactive energy customer."

The shared integrated grid as it is described above is entirely consonant with the legislative objectives of RSA 53-E, RSA 374-F, and the emphasis on competitive markets in New Hampshire's constitution. It specifically enables the state's energy systems to become more distributed, responsive, dynamic, and consumer-focused. It promotes innovative business applications that will save customers money, allow them to make better and more creative use of the electricity grid, and facilitate municipal and county aggregation programs authorized by RSA 53-E. It will enable animated and competitive retail electricity markets and help customers to obtain lower electric costs, reliable service, and secure energy supplies. It also emphasizes the type of ***effective collaboration*** that Gov. Sununu has sought by writing: "*The key for the long-term success of community aggregation will be stakeholders engaging in constructive dialogue to reach achievable policy goals".* In short, the shared integrated grid is the leading industrial concept for New Hampshire to achieve its objectives.

While a shared integrated grid can realize the legislative objectives of RSA 53-E, in many ways its implementation has been elusive for a variety of non-technical and often implicit barriers. The distinguished energy economist Dr. Ahmad Faruqui in his recent article in the journal Regulation entitled "Refocusing on the Consumer: Utilities' regulation needs to prepare for the "prosumer" revolution" recounts the more than 50-year saga of trying to advance a basic building block of grid modernization: customer access to meaningful choices of time-varying rates. [Attachment 5] . He summarizes this saga and the current state grid of modernization in this way:

"It's obvious that both regulators and energy executives are frozen in time and they know it. They spend much of their time blaming each other for the delays. The blame game continues unabated at many industry events. The pace, ambiguity, and inconclusiveness of this regulatory drama seem to be a reenactment of the play Waiting for Godot. . . . "

"While every state is in a big rush to move ahead with decarbonization and has specified some very aggressive timelines for becoming 100% decarbonized, just about all the policy solutions are on the supply side. There is almost no inclusion of dynamic load flexibility, which could help deal with the intermittent nature of renewable energy."

"For those of us who work in the electric utility industry, the time has come to rethink regulation, reimagine the utility, and reconnect with the real customer. That journey can no longer be delayed. …This journey will involve finding new ways to engage with customers and observing those customers in real-time to understand their energy-buying decisions. Unless these steps are undertaken, the customer is going to leave both the utility and the regulator in the dust."

The enactment of RSA 53-E and RSA 374-F provide a legal pathway to overcome these implicit barriers and realize the Shared Integrated Grid and create quantifiable synergistic benefits in New Hampshire. My laboratory at the Thayer School of Engineering at Dartmouth recently conducted

the New England Energy Water Nexus Study as a collaborative project, funded by the United States Department of Energy, and now published in the prestigious peer-reviewed journal Renwable and Sustainable Energy Reviews [Attachment 6].

Balancing Performance	
Average Load Following Reserves	1.24–12.66%
Average Ramping Reserves	5.28–18.35%
Percent Time Curtailed	2.67–10.90%
Percent Time Exhausted Regulation Reserves	0%
Std. Dev. of Imbalances	3.874–6.484%
Environmental Performance	
Total Water Withdrawals	0.65–25.58%
Total Water Consumption	1.03–5.30%
Total CO_2 Emissions	2.10–3.46%
Economic Performance	
Total Day-Ahead Energy Market Production Cost	29.30–68.09M$
Total Real-Time Energy Market Production Cost	19.58–70.83M$

Figure 5. A Balanced Scorecard from the New England Energy-Water Nexus Study Showing the Quantifiable Cross-the-Board Synergistic Benefits of Flexible Energy-Water Resources.

The premise of the project was to quantify the benefits of using "energy-water resources" like water heaters, water utilities, and wastewater utilities as flexible resources in the ISO New England energy markets. The values shown in Fig. 5 assume a modest penetration of ~5% of peak electricity load of these resources. The wide ranges in values stem from six different future energy scenarios; ranging from "business-as-usual" to "high renewables". Fig. 5 summarizes the final conclusion of the work: ***In ALL the future energy scenarios studied, enabling the flexible participation of energy-water resources improves the grid's reliable balancing operation, improves the grid's environmental performance in terms of water use and CO2 emissions, and saves tens of millions of dollars per year for New England's residents WITHOUT trade-off.***

The primary impediment to realizing these benefits is that real-time prices that we see in the wholesale electricity markets must translate down to customers with energy-water resources in the distribution system. The Shared Integrated Grid is the techno-economic vehicle for real-time pricing transacive energy service in the distribution system. RSA 53-E, in turn, is the legislative vehicle for enabling the Shared Integrated Grid through CPAs. Therefore, I urge the New Hampshire legislature to "stay-the-course" and oppose HB315 for what it is: a regressive bill that hinders market competition, systemic innovation, and a whole host of quantifiable technical, economic, and environmental benefits.

VI. Conclusion

This testimony that I have provided here is that of a volunteer and engaged citizen-scientist. It is my technical opinion based on a decade of well-developed academic credibility, and accumulated scientific expertise in power systems engineering and economics. I can attest that my testimony is free from any financial conflict of interest; including with any of the investor owned utilities and with any of the emerging community power aggregators. As a voting citizen and an Eversource rate payer, it is my preference to purchase electricity from another source; if given the choice. As a scientist and academic, my research publications demonstrate extensive evidence that such market competition and innovation would spur synergistic technical, economic and environmental benfits across the state; as RSA 53:E, RSA 374, and the state constitution intend.

Sincerely,

Dr. Amro M. Farid
Associate Professor of Engineering
Adjunct Associate Professor of Computer Science
Laboratory for Intelligent Integrated Networks of Engineering Systems (LIINES)
Thayer School of Engineering at Dartmouth
CEO of Engineering Systems Analytics LLC

Towards a Shared Integrated Grid in New England's Energy Water Nexus

Steffi Muhanji[1], Clifton Belows [2], Tad Montgomery [3] and Amro M. Farid[4]

***Abstract*— The electric power system is rapidly decarbonizing with variable renewable energy resources (VREs) to mitigate rising climate change concerns. There are, however, fundamental VRE penetration limits that can only be lifted with the complementary integration of flexible demand-side resources. A recent study has shown that flexible energy-water resources can serve such a role, provide much needed operating reserves and cost-effectively reduce power system imbalances. The implementation of such demand-side resources necessitates a "shared integrated grid" that is characterized by: 1) integral social engagement from individual electricity consumers 2.) the digitization of energy resources through the energy internet of things (eIoT), and 3) community level coordination. This paper discusses the efforts of Dartmouth College and the City of Lebanon, NH to develop such a shared integrated grid. It leverages the newly passed New Hampshire municipal aggregation bill to develop a prototype transactive energy (TE) market that enables Lebanon residents to trade carbon-free electricity products and services amongst themselves.**

I. Introduction

The electric power system is rapidly decarbonizing to mitigate rising climate change concerns. This evolution to a carbon-free grid has been characterized by a widespread adoption of variable renewable energy resources (VREs) such as solar and wind throughout the electricity supply chain. In the meantime, VRE adoption has been driven by a combination of technology improvements, favourable legislation and lower costs. While much VRE integration has been in the form of utility-scale developments, more recent integration, particularly roof-top solar has been at the consumer level, behind-the-meter, as distributed generation (DG).

VREs, however, pose fundamental challenges to the technical and economic control of the power grid. First, these resources are highly variable and erode the dispatchable nature of the generation fleet [1]. Second, both solar and wind power profiles are influenced by external factors such as wind-speed and solar irradiance that are challenging to predict and leverage in grid operations. Grid operators must rely on forecasted VRE power profiles in order to dispatch generation so as to meet demand in real-time. Such forecasts are error-prone and, therefore, impede system operators' ability to exactly match generation and demand. Third, the eroded dispatchability of the generation fleet impedes its ability to track the net load. Whereby "net load" is defined as the difference between the aggregated system load and the total generation produced by VREs, tieline imports/exports, and any transmission and distribution losses. Fig. 1 represents a phenomenon commonly referred to as the "duck curve". The black line represents the net load. With each gigawatt (GW) of solar added, the "belly" of the net load curve grows. As the sun rises over the course of the day, an increasing number of dispatchable generators are taken offline. As the sun sets, these same generators must start up and ramp up quickly to replace the waning solar generation [1], [2]. Incidentally, this ramp also happens to coincide with the evening electricity demand peak. These challenges greatly limit the extent to which VREs can be adopted within the current electricity grid set up.

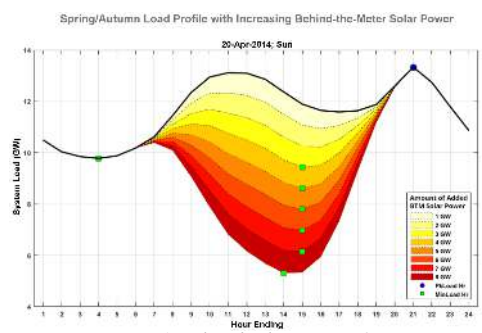

Fig. 1: The duck curve. [2]

Indeed, dozens of renewable integration studies across varied geographies have come to the following consensus conclusions [1]–[6]:

1) VREs require greater quantities of normal operating reserves.
2) Both the variability and forecast errors of VREs contribute towards system imbalances.
3) VREs present dynamics that span multiple time scales and layers of power system control.

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4) Operators are forced to take corrective manual actions to deal with real-time variability.
5) VRE forecast errors can impede real-time energy markets from clearing. The associated optimization models result in infeasible solutions.
6) Operating a system with high amounts of VREs requires even greater quantities of ancillary services.

These conclusions not only call for holistic and integrated solutions but also the need to significantly increase available grid services [7].

Engaging the demand-side has been proposed as a key control lever towards effective VRE integration [1], [8]. Firstly, the grid periphery is increasingly activated by "smart-home" distributed energy resources (DERs); be they in the form of rooftop solar, electric vehicles (EVs), or battery energy storage. Secondly, electricity consumers are becoming more conscious of the cost and sustainability of their consumption patterns [1], [8], [9]. Thirdly, the deregulation of electric power systems has steadily disbanded traditional generation monopolies and opened the way for increasing consumer choice in electricity service. Finally, the rise of the energy Internet of Things (eIoT) and its associated data-driven services have modernized the electricity demand-side, incentivized new types of grid actors (e.g demand aggregators), and inspired new retail services [1], [8], [9]. When these seemingly independent developments converge to maturation, they form transactive energy (TE) market places that cost-effectively transact electricity "products" amongst everyday grid "prosumers", reliably secure the physical power grid, and seamlessly inter-operate with wholesale (bulk) electricity markets. Coupled with favourable local legislation, American communities are now able to take control over their electricity needs through various community energy aggregation schemes. These factors allow consumer choice of energy provider, foster the development of local renewable energy and facilitate the formation of market structures in which local consumers exchange energy products and services both with their local neighbours and with the grid as a whole [1], [9].

A. Contribution

This paper seeks to tie the "macro-picture" of grid decarbonization and VRE integration into the "local-picture" of community efforts towards a ***shared integrated grid***. First, it draws on the lessons learned from the ISO New England's (ISO-NE) 2017 System Operational Analysis and Renewable Energy Integration Study (SOARES) to illustrate the fundamental limits to VRE integration. Specifically, in the absence of complementary demand-side initiatives, the electric power system develops a notable dependence on VRE curtailment as a key control lever. Second, this paper demonstrates that the needed control levers can come from the flexible operation of a modest percentage of New England's energy-water resources. Doing so would enhance the grid's balancing performance, CO_2 emissions, water withdrawals and consumption, and real-time/day-ahead market production costs. To achieve such a synergistic outcome, the paper presents a concept of a shared integrated grid that is characterized by: 1) integral social engagement from individual electricity consumers, 2) the digitization of energy resources with eIoT, and 3) community level coordination. The City of Lebanon NH and Dartmouth College are currently collaborating towards its implementation in the form of a Transactive Energy (TE) Blockchain prototype.

B. Outline

The rest of the paper is structured as follows. Section II, discusses the key findings and lessons learned in the SOARES. Section III presents the New England energy water nexus study results and conclusions. Section IV discusses ongoing efforts towards a shared integrated grid in NH. Finally, the paper concludes in Section V.

II. Motivation — The Curtailment problem.

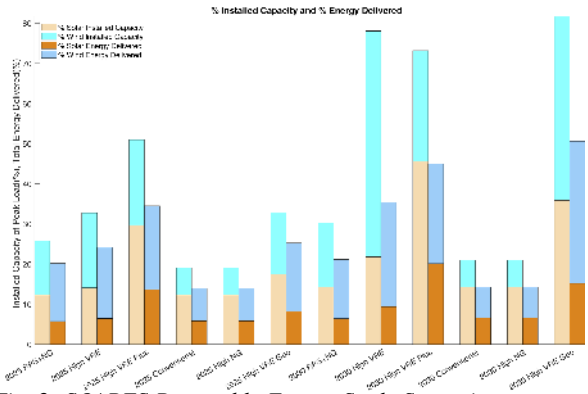


Fig. 2: SOARES Renewable Energy Study Scenarios as agreed by ISO-NE stakeholders [?].

A. Study Description

In 2017, ISO-NE commissioned the System Operational Analysis and Renewable Energy Integration Study (SOARES) to investigate the impact of varying penetrations of VREs on the operations of the ISO-NE system. This study looked into 12 predefined (by the New England Power Pool (NEPOOL)) scenarios with 6 in 2025 and 6 in 2030 [2]. These scenarios were distinguished by the capacity and diversity of dispatchable generation resources, solar, wind, and energy efficiency. Fig. 2 represents the installed capacity of and actual energy delivered by solar and wind for each of the 12 scenarios. The "2025/2030 Conventional" scenario reflects the

ISO-NE system if it were to evolve in a "business-as-usual" manner. Due to the high penetrations of solar and wind, most scenarios experienced a negative "net load" during low load periods in the Spring and Fall months. In addition, nuclear generation units were considered "must-run" resources and therefore, generated electricity at all times and at full capacity [2]..

B. Highlights of Key Results

The dispatched generation profile for the "2030 VRE Plus" scenario in mid-April is shown in Fig. 3. The majority of the generation is met by wind, solar, and nuclear power. At any one point in time, very few dispatchable generators are committed. Note that with such high amounts of VREs, the commitment of dispatchable generators is no longer a trivial issue but rather, one that is difficult to predict as it is highly influenced by both the non-linear dynamics of VREs and the statistics of the net load profile [2]. Such high VRE penetration levels significantly impact the system's ability to deal with net load variability and hence mitigate imbalances in real-time. For example, at midday, large amounts of solar result in low load conditions and test the system's ability to ramp downwards. The opposite is observed as the sun begins to set whereby the system must ramp upwards to compensate for the declining generation. As Fig. 3 shows, instead of the traditional "duck curve" (as in Fig. 1) an even more exaggerated profile (called here the "duck-dive curve") is observed for the "2030 VRE Plus" scenario. The sharper ramp in this Fig. 3 further illustrates the operational constraints presented by high penetrations of VREs.

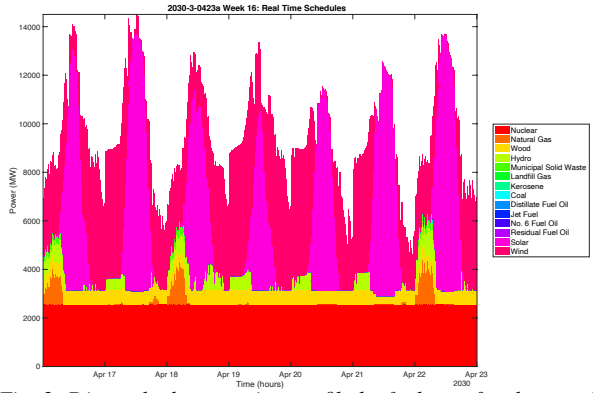


Fig. 3: Dispatched generation profile by fuel type for the month of April.

For the scenarios with a significant presence of VERs ("High VREs", "High VRE Plus" and "High VRE GEO"), the system is shown to entirely exhaust both its upward and downward load-following as well as ramping reserves [2]. Where load-following reserves represent the available capability by online generators to move up or down and ramping reserves is the ability of online generators to move up or down per unit time. Figures 4 and 5 illustrate load-following and ramping reserves for the "High VREs Plus" scenario. Both the load-following and ramping reserves go to zero in the Fall and Spring months. The minimum statistic of both reserve quantities is particularly important as it indicates the "safety margin" that the system has to ensure its security. As the third subplots of Figures 4 and 5 respectively illustrate, both types of reserves have a zero minimum. Incidentally, the exhaustion of these reserve quantities corresponds to even higher imbalances as the system is unable to respond to variability in the net-load in real-time. These results challenge the assumptions around the acquisition of these reserve quantities and motivate the need for better techniques to obtain them.

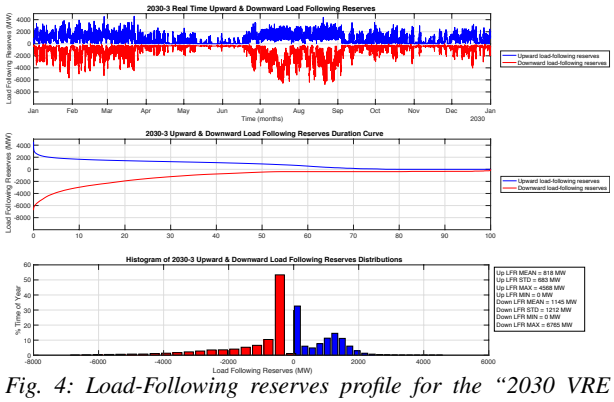


Fig. 4: Load-Following reserves profile for the "2030 VRE Plus" scenario [2].

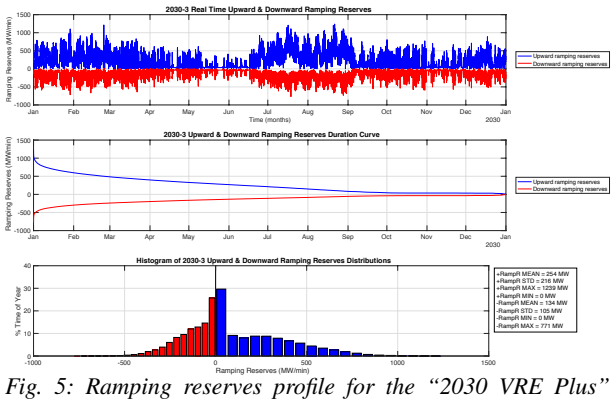


Fig. 5: Ramping reserves profile for the "2030 VRE Plus" scenario [2].

Perhaps the most insightful finding of this study is the reliance on curtailment to maintain the system's normal operating conditions. For all of the 12 scenarios, curtailment of VREs emerged as a key control lever in addition to the load-following and ramping reserves provided by dispatchable generators. Each scenario utilized curtailment as a balancing lever at least 98% of the time [2]. More interestingly, the total energy curtailed ranged from 2.72% of the total available VRE capacity for the conventional scenarios to 41.19% for scenarios with high penetrations of VREs [2]. While some of the

curtailment was due to excessive VRE generation in the system, a small portion of this curtailment was caused by topological limitations of the system. Curtailment is especially vital when variable resources are situated in remote locations such as Northern Maine. In these cases, it can be the only available control lever [2].

Irrespective of the reason for curtailment, the extent to which curtailment was used in all these simulation scenarios is potentially concerning. Although increasing the line-carrying capacity would alleviate the need for curtailment in cases with topological constraints, building more transmission is not always an option in most regions. Furthermore, lower levels of curtailments are vital as they increase the overall amount of generation from renewable sources, and reduce the use of expensive dispatchable generation; which in turn cuts costs and CO_2 emissions. This study illustrates the indispensable role of curtailment in power system balancing performance.

Mathematically speaking, curtailment is not unlike load-following and ramping reserves. The curtailment signal used in this study moved the power levels of a given curtailable resource up or down within the real-time resource scheduling market time step of 10 minutes. This means that to curtail a VRE, this resource must ramp up/down from its current production level to the curtailed level within 10 minutes. The ramping of a VRE as it reduces its generation level could count towards the system ramping reserves and be compensated accordingly. Similarly, the total power available for curtailment from any given VRE could also count towards the system load-following reserves. Reconciling the definitions of operating reserves and curtailment and, therefore, their treatment in electricity markets would go a long way to provide the much needed flexibility in systems with high penetrations of VREs. Semi-dispatchable resources (i.e. resources whose supply can be curtailed) could provide load-following and ramping reserves. Similarly, a much faster curtailment signal can help develop regulation reserves.

III. Results from the New England Energy-Water Nexus Study

TABLE I: A summary of available flexible water resources in the system as percentage of the peak load.

	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Hydro Run-of-River & Pond	1854MW (6.21%)	1788MW (5.99%)	1646MW (7.10%)	1782MW (5.97%)	1798MW (5.99%)	1784MW (5.97%)
Pumped Storage	1758MW (6.15%)	1758MW (6.15%)	1758MW (6.15%)	1758MW (6.15%)	1758MW (6.15%)	1758MW (6.15%)
Water Load	565MW (1.89%)	565MW (1.89%)	565MW (2.44%)	565MW (1.89%)	565MW (1.89%)	565MW (1.89%)
System Peak Load	28594 MW	28594 MW	22103MW	28594MW	28594 MW	28594 MW

The findings of the SOARES are significant in two main ways. First, they highlight the value of curtailment in balancing performance, and second, they show the need to engage more demand-side resources in market operations. With these conclusions in mind, the New England Energy-Water-Nexus study was conducted to analyze: 1) the value of curtailment in the provision of load-following, and ramping reserves, 2) the value demand response by energy-water resources of various types, 3) the fuel flows of thermal units and their associated CO_2 emissions, 4) water withdrawals and consumption by thermal units, and 5) the effect of flexible operation on the New England energy market production costs. This study combines the two main insights of the SOARES, by redefining the role of curtailment in power system operation and activating energy-water demand-side resources . The first goal is achieved by allowing curtailment to count towards the provision of both load-following and ramping reserves. The second is achieved by allowing energy-water resources to provide demand response through their load-shedding capabilities.

The New England Energy Water Nexus study considered 6 2040 scenarios for the ISO-NE system. The resource mixes for the six 2030 scenarios of the SOARES were evolved to 2040 scenarios using the Regional Energy Deployment System (ReEDS) optimization tool developed by the National Renewable Energy Lab (NREL). Table I summarizes the capacity mixes of all the energy-water resources used in this study. Two modes of operation were considered: flexible operation (with flexible energy-water resources) and conventional operation (without them). In the flexible mode, run-of-river and pond-hydro were curtailable at a cost of $\$4.5/MWh$ while demand from water and wastewater treatment facilities had a load-shedding capability. The opposite was true for the conventional operation mode. Pumped storage was treated as a dispatchable resource across all six scenarios in both operating modes.

The "flexibility value" of coordinated flexible operation of the New England energy-water nexus was assessed based on three main areas: 1) balancing performance (improvements in load-following, ramping and regulation reserves, curtailment, and system imbalances), 2) environmental impact (reductions in water withdrawals and consumption, and CO_2 emissions) and 3) overall production costs (day-ahead and real-time). Table II summarizes the range of improvements brought about by coordinated flexible operation of the New England Energy water nexus.

A. Balancing Performance

Flexible operation enhanced the mean upward and downward load-following reserves by 1.26%-12.66% across the six 2040 scenarios as illustrated in Table II. The study also showed that flexible operation significantly improves the minimum levels of load-following

TABLE II: Balanced Sustainability Scorecard: The range of **improvements** *caused by coordinated flexible operation of the energy-water nexus.*

Balancing Performance	**% Improvement**
Average Load Following Reserves	1.24–12.66%
Average Ramping Reserves	5.28–18.35%
Percent Time Curtailed	2.67–10.90%
Percent Time Exhausted Regulation Reserves	0%
Std. Dev. of Imbalances	3.874–6.484%
Environmental Performance	**% Improvement**
Total Water Withdrawals	0.65–25.58%
Total Water Consumption	1.03–5.30%
Total CO_2 Emissions	2.10–3.46%
Economic Performance	**% Improvement**
Total Day-Ahead Energy Market Production Cost	29.30–68.09M$
Total Real-Time Energy Market Production Cost	19.58–70.83M$

reserves across all six scenarios and in some cases by up to 82.96%. The results indicate that by adding a small amount of flexibility in the system (see Table I), the robustness of the system is improved in the worst case points and the overall operation during challenging periods.

Similarly, the mean downward and upward ramping reserves values were improved by 5.28%-18.25% with flexible operation as shown in Table II. The minimum statistic of ramping reserves improved across all six scenarios with up to 31.65% for downward ramping reserves and up to 47.32% for upward ramping reserves. These improvements were greater for systems with a high penetration of VREs. This result further illustrates the role of curtailment in improving the flexibility of the system if applied towards the provision of load-following and ramping reserves.

Although, flexible operation increased the amount of power available for curtailment, the results of the study showed that flexible operation reduced the percent of time VREs were curtailed by 2.67%–10.90%. Contrasted with the SOARES where curtailments occurred up to 98% of the time [2], flexible operation significantly improves the use of curtailment and, therefore, renewable energy in power system operations. Also, due to flexible operation, regulation reserves were exhausted for 0% of the time unlike the SOARES where they exhausted 0.14%–46.20% of the time. Finally, the standard deviations of imbalances decreased by 3.874%-6.484%. These results illustrate that by revising the role of curtailment in power system operation and engaging demand-side resources, the overall security of the system is improved through increased flexibility in balancing performance.

B. Environmental Impact

Flexible operation reduced the environment impact of the electric power grid by reducing the water withdrawals and consumption by thermal power plants by 0.65%–25.58% and 1.03%–5.30% respectively. Similarly, the overall CO_2 emissions were reduced by 2.10%–3.46%. These results indicate that an even bigger environment impact is likely with increased flexible operation and demand-side participation.

C. Economic Impact

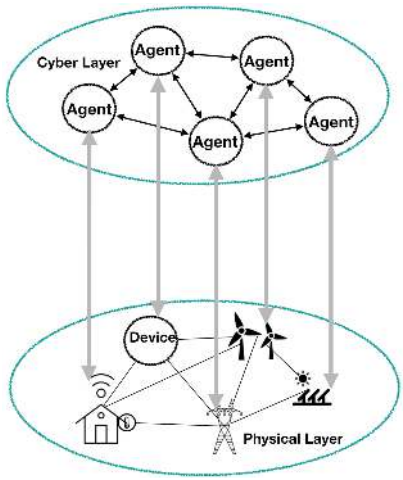
Finally, flexible operation reduced the overall electricity production cost by 29.30–68.09M$ for the day-ahead market and 19.58–70.83M$ as compared to the conventional mode of operation. These results indicate that the flexible mode of operation allows for less constrained day-ahead and real-time optimization programs, that, in turn, result in reduced overall production costs.

IV. Discussion

The New England energy-water-nexus study showed that the introduction of small quantities of flexible energy-water demand-side resources could have far-reaching consequences on all aspects of power system performance. Nevertheless, there are many challenges to realizing the benefits of flexible energy-water demand side resources; be they water treatment plants, wastewater treatment plants, or even everyday household electric water heaters. First, they are owned and operated by individual electricity consumers; with their own objectives for their use. Second, many such devices lack the necessary instrumentation and control technology to become active grid resources. Third, they are both small and connected to the distribution system and consequently lack the ability to have noticeable impact

on wholesale bulk power system operation. To overcome these challenges and achieve the synergistic outcomes of the New England energy-water nexus study, this paper presents the concept of a ***shared integrated grid*** that is characterized by: 1) integral social engagement from individual electricity consumers, 2) the digitization of energy resources with eIoT, and 3) community level coordination.

Fig. 6: Summary of available generation capacity as a percentage of total available capacity by fuel type for all six 2040 scenarios.



To that effect, and following on the recent enactment of NH Senate Bill 286, the City of Lebanon NH has launched Lebanon Community Power (LCP) as a municipal load aggregation initiative. The main objective of the initiative is to enable consumer choice in newly animated retail electricity markets so that smaller electricity consumers can benefit from the savings and rate alternatives that wholesale customers already enjoy. In so doing, the municipal aggregation gives access to real-time electricity prices that are on-average lower compared to the fixed retail rates. Furthermore, the local transactions of energy with Lebanon can serve to bolster renewable energy adoption, load reduction, and decarbonization as a whole. Furthermore, at the city level, the presence of municipal load aggregation can catalyze other initiatives like electric vehicle charging stations, smart street-lighting, and the deployment of other DERs like battery and thermal energy storage. A key component of the LCP initiative is to obtain granular meter data through collaborating with Liberty Utility to support research efforts to guide the deployment of DERs. This will involve meter upgrades to enable near-real time readings.

With these factors in mind, the Laboratory for Intelligent Integrated Networks of Engineering Systems (LIINES) at the Thayer School of Engineering at Dartmouth has teamed-up with LCP to develop a Transactive Energy (TE) Blockchain prototype to support the LCP initiative. The goal of the TE platform is to support real-time market transactions while ensuring that the Lebanon electric power system continues to function securely and reliably. Transactive energy (TE) is defined as "a system of economic and control mechanisms that allow the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter." Central to the development a TE prototype as the economic backbone of the LCP is the integration of power systems control engineering to secure grid's many operational and technical constraints. The technical development of the TE prototype draws on key lessons from the technical literature distributed control algorithms and multi-agent systems. Furthermore, the LIINES is collaborating with Liberty Utilities so the TE prototype addresses the specific complexities of the Lebanon distribution system.

In a TE context, each physical DER participates as a market agent in a cyber (or market) layer. As a design principle to minimize complexity and ensure privacy, each agent in the cyber layer only holds and exchanges information that is relevant to their specific participation in the market. It then carries out local and coordinated cost-minimization algorithm that simultaneously respects operational and physical constraints of the system. Given the magnitude of information exchange, Blockchain serve as a secure and distributed ledger to record and store transactions that each agent can ultimately access and verify.

V. Conclusion

In conclusion, the technical development of the transactive energy blockchain prototype coupled with the legislative enactment of SB 286 serve to enable the Lebanon Community Power initiative. While the LCP may be classified as a type of Community Choice Aggregator, this particular conception demonstrates several advanced features including: 1.) working with innovative private-sector partners to expand market access, 2.) working with utilities and technology developers to deploy the right IT infrastructure, and 3.) working with wide range of public and private stakeholders to ensure that the market structure continues to evolve and embraces new technologies — under a nimble, flexible mode of governance. These characteristics are integral to a truly "shared integrated grid" that through continued innovation in energy policy, markets, and technology platforms expands consumer choice, enables the flexible operation of demand-side resources, reduces electricity costs, facilitates greater adoption of renewable energy and ultimately accelerates the decarbonization of the electric power sector.

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Developing a Blockchain Transactive Energy Control Platform in Lebanon to Transform the New Hampshire Electricity Market.

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***Abstract*—The electricity distribution system is fundamentally changing due to the widespread adoption of distributed generation, network-enabled physical devices, and active consumer engagement. These changes necessitate new control structures for electric distribution systems that leverage the benefits of integral social and retail market engagement from individual electricity consumers through active community-level coordination to support the integration of distributed energy resources. This work discusses a collaboration between Dartmouth, the City of Lebanon New Hampshire (NH) and Liberty Utilities to develop a transactive energy control platform for Lebanon. At its core, this work highlights the efforts of determined communities within the state of New Hampshire seeking to democratize energy and spearhead the sustainable energy transition. The work implements a distributed economic model-predictive control (MPC) formulation of a dynamic alternating current (AC) optimal power flow to study the flows of power within the Lebanon distribution grid. It employs the recently proposed augmented Lagrangian alternating direction inexact newton (ALADIN) distributed control algorithm that has been shown to guarantee convergence even for non-convex problems. The paper demonstrates the simulation methodology on a 13 node Lebanon feeder with a peak load of 6000kW. Ultimately, this work seeks to highlight the added benefits of a distributed transactive energy implementation namely: lowered emissions, cheaper cost of electricity, and improved reliability of the Lebanon electric distribution system.**

I. Introduction

In recent years, community choice aggregations (CCAs) have emerged as a means to democratize electricity supply for consumers [1]. CCAs are generally run by a public entity such as a municipality or a county government to procure wholesale electricity for its consumers while the utility continues to offer transmission and distribution services [1]. CCAs democratize electricity procurement by offering consumers access to a broader portfolio of electric services, often at more competitive prices, with renewable energy penetration that can exceed Renewable Portfolio Standards (RPS) requirements [1], [2]. CCAs first emerged in the state of Massachusetts in 1999 after the passage of the state's Community Choice Aggregation (CCA) law in 1997 [1]. Since then, CCAs have been implemented in 8 other states namely California, Illinois, New Jersey, New York, Ohio, Rhode Island, Virginia, and most recently New Hampshire [1]. In New Hampshire, the authorities of CCAs have been expanded to not just provide default wholesale supply, but also retail customer services that monopoly distribution companies have heretofore provided to the mass market, such as community-provided consolidated billing, meter reading and related functions critical to enabling Transactive Energy. This new model is referred to as "Community Power Aggregation" (CPA). This paper discusses the emergence of CPAs in the state of New Hampshire and more specifically outlines the plan by the City of Lebanon NH to design a cost effective and resilient electric distribution system based on transactive energy market principles.

II. Community Power Aggregation in New Hampshire

Through a collaboration with Liberty Utility and the Laboratory for Intelligent Integrated Networks of Engineering Systems (LIINES) at the Thayer School of Engineering at Dartmouth, the City of Lebanon is developing Lebanon Community Power (LCP) as a municipal load aggregation initiative. The primary goal of this initiative is to enable consumer choice, reduce the overall costs of electricity by offering real-time prices and/or time-of-use rates among other pricing options, as a means to accelerate the development and adoption of local renewable energy resources. What is most interesting and unique about the LCP initiative is their desire to develop

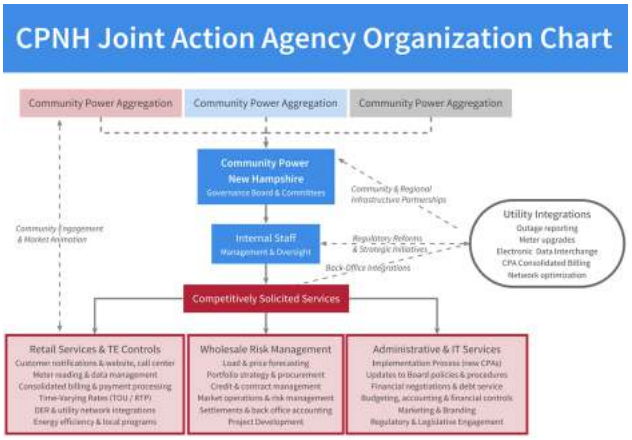

Fig. 1. The proposed organizational chart of the joint action agency (Community Power New Hampshire) under formation.

a transactive energy market to foster an active retail market where consumers can trade in a variety of electricity products and services while also ensuring the overall resilience of their electricity grid. In addition, the city has undertaken several steps to improve its energy portfolio by investing in smart street-lighting, building energy conversion, small-scale hydro, landfill gas-to-electricity, and electric vehicle (EV) charging infrastructure. It has also participated in a household battery pilot. These efforts benefit greatly from the enactment of two major bills: the statewide, multi-use online energy data platform bill (SB284) [3] and the NH municipal aggregation bill (SB286) [4].

SB284 establishes a state-wide multi-use online energy data platform to provide consumers and stakeholders access to safe and secure information about their energy usage [3]. This data platform provides access to robust data that increases awareness of energy use, and supports municipal/county aggregations through better planning and understanding of market dynamics [3]. The development of this energy data platform is underway with the NH Public Utilities Commission (NH PUC) docket DE 19-197[1]. There, the authors have advocated model-based system engineering (MBSE) principles to collect, aggregate, and anonymize consumer electricity use data in a way that is easy to access and allows for a variety of research applications and business cases [3]. In addition, this data platform will likely consists of an application programming interface (API) that various stakeholders can use to meet their data needs [3]. By allowing transparency and data access, this bill facilitates the establishment of municipal and county aggregations that can draw from this data to make informed decisions about the energy usage of their residents and collaborate easily with utilities. In the meantime, the SB286 allows for municipalities to form aggregations so as to procure electricity and energy services on behalf of their consumers. Consumers that do not ***opt-out*** of the aggregation agree to have the municipality or county government supply their electricity and provide other services such as demand side management, meter services, and energy efficiency and renewable energy acquisition. Together, these two bills promote not only the formation of CCAs but also allow for broader collaboration among New Hampshire communities.

Since the enactment of the SB284 and SB286, collaboration among New Hampshire community energy groups has increased significantly. To foster these collaborations and knowledge sharing, Lebanon and several other New Hampshire Communities have come together to collectively form a Joint Action Agency called: "Community Power New Hampshire". As Figures 1 and 2 depict, for every Community Power Aggregation that elects to join the governance board and share in the cost of services, the agency will enroll default electricity service customers on an opt-out basis and assume control of wholesale and retail functions, irrespective of distribution utility territory, per the authorities granted under SB286. The Joint Action Agency is designed to catalyze market transformation both by implementing these systems on a statewide basis for participating communities, and by coalescing communities to speak with one voice at the regulatory commission and legislature to support necessary rule reforms and broader investments in common infrastructure to enable Transactive Energy. Together, these communities establish the concept of a ***shared integrated grid*** that is characterized by: 1) integral social and retail market engagement from electricity consumers, 2) the digitization of energy resources with the energy internet of things (eIoT), and 3) widespread community-level coordination [5].

Fig. 2. Educational material explaining Community Power Aggregation (CPA) authorities.

A. Contribution

This paper seeks to tie the "macro-picture" of activating the demand-side into the "social-picture" of integral community engagement in the form of community power to establish a shared-integrated grid. First, it presents the efforts within New Hampshire to develop municipal/county-level aggregations and a state-wide online data platform. These efforts indicate a clear determination towards the sustainable energy transition as well as integral social engagement at the community and state level. Second, this paper discusses the collaboration between the City of Lebanon, NH, Liberty Utilities and Dartmouth College to develop a transactive energy prototype for the city. It presents the overall structure of the transactive

[1][fn] See tab 65 at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197.html

energy platform, introduces key mathematical concepts employed in the TE prototype and the data to be utilized in the study.

B. Outline

This paper is structured as follows. Section II, discusses the development of community power aggregations within New Hampshire. Section III presents the transactive energy implementation for the Lebanon Community Power. Section IV presents simulation results on a simple 13 node feeder in Lebanon. Finally, the paper concludes in Section V.

III. The Transactive Energy Model

The Lebanon-LIINES collaboration presents a realization of this shared-integrated grid concept. The LIINES is currently tasked with developing a transactive energy control prototype to support the LCP initiative. The goal of the TE platform is to support real-time market transactions of the aggregation while ensuring that the Lebanon electricity distribution system continues to function securely and reliably. The prototype transactive energy market is to be secured through blockchain for Lebanon residents to trade carbon-free electricity products and services with each other. It employs a distributed control algorithm that is better able to scale with the accelerating explosion of actively-controlled eIoT devices than a comparable centralized algorithm; thereby enabling a new generation of energy prosumers and entrepreneurs to engage in the grid's transactive energy markets.

At its core, the TE model implements an economic model predictive control (E-MPC) formulation of the alternating current optimal power flow (ACOPF). The (ACOPF) is chosen as it offers the full implementation of the "power flow equations" which, in turn, are a pseudo-steady state model of Kirchkoff's current law [6], [7]. This allows the model to fully capture the dynamics of the electricity distribution system. Although most implementations of the ACOPF are single time-step optimizations, an E-MPC formulation of the problem is used here to fully capture the multi-timescale dynamics introduced by variable renewable energy resources (VREs) such as solar and wind. MPC is an optimal feedback control technique that uses the dynamic state of a system to predict over a finite and receding time horizon how the state of the system evolves and uses only the solution for the first time-step to update the system for the next optimization block [8].

This study focuses on distribution systems comprise of large numbers of distributed energy resources and digital devices hence a scalable distributed control algorithm is implemented. Several distributed control algorithms have been proposed in literature to address the challenges of controlling the large number of active grid-edge devices. However, the majority of these algorithms don't guarantee optimality for non-convex, non-linear problems such as the ACOPF and therefore, seek to linearize the ACOPF to either the DCOPF, or to convex variants through the semi-definite and second-order cone programming (SOCP) relaxations [9], [10]. While linearization offers various convergence benefits, it generally fails to capture the physical dynamics of the distribution systems. In addition many of the proposed distributed control algorithms such as the Alternating Direction Method of Multipliers (ADMM), Alternating Target Cascading (ATC), and Dual Ascent have practical implementation weaknesses that make them unreliable when applied to large-scale applications [11]. The most common distributed control algorithm is the ADMM which has been widely studied in literature in its application to the electric power grid [12], [13]. Unfortunately, recent studies have shown that the convergence of the ADMM depends highly on the choice of tuning parameters in convex spaces and is all-together not guaranteed in non-convex spaces such as the ACOPF [11]. In recent years, the ALADIN algorithm has been proposed in the literature as not just an alternative to the ADMM but also as a solution with better convergence guarantees even for non-convex applications [14], [15]. For these reasons, this work implements the ALADIN algorithm.

A. The AC Optimal Power Flow Problem

The ACOPF calculates the steady-state power flows within a given electricity grid. It is comprised of an objective function in the form of a cost minimization, social welfare maximization, or transmission loss minimization among others. It is usually constrained by generation capacity limits, voltage magnitude limits, and the power flow constraints but other constraints may be added depending on the need. The traditional ACOPF formulation is presented below:

$$min \quad C(P_G) = P_G^T C_2 P_G + C_1^T P_G + C_0 \mathbf{1} \tag{1}$$

$$s.t. \quad A_G P_G - A_D \hat{P}_D = Re\{diag(V) Y^* V^*\} \tag{2}$$

$$A_G Q_G - A_D \hat{Q}_D = Im\{diag(V) Y^* V^*\} \tag{3}$$

$$P_G^{min} \leq P_G \leq P_G^{max} \tag{4}$$

$$Q_G^{min} \leq Q_G \leq Q_G^{max} \tag{5}$$

$$V^{min} \leq |V| \leq V^{max} \tag{6}$$

$$e_x^T \angle V = 0 \tag{7}$$

where e_x is an elementary basis vector that defines the xth bus as the reference bus. Equation 1 represents the quadratic generation cost function where P_G is the vector of power injections from power plants, C_2, C_1, and C_0 are the quadratic, linear, and fixed cost coefficients of the generation fleet. Note that C_2 is a diagonal matrix and so the generation cost objective function is separable by generator. It may be equivalently written as:

$$C(P_G) = \sum_{g \in G} c_{2g} P_g^2 + c_{1g} P_g + c_{og} \tag{8}$$

To continue, Equations 2 and 3 are the active and reactive power flow constraints respectively where $\hat{P}_D$ is the forecasted electricity demand for electricity. A_G and A_D are the generator-to-bus and load-to-bus incidence matrices for generators and loads. Equations 4, 5, and 6 represent the capacity limits on active power injections, reactive power injections and bus voltage limits respectively. Finally, 7 sets the voltage angle of the chosen reference bus to 0.

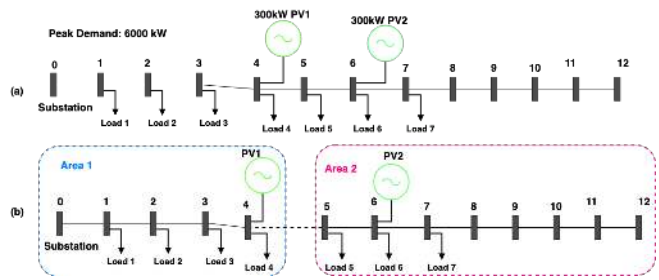

Fig. 3. A simple 13 node feeder.

B. A Generic Non-linear Economic MPC Formulation

Model predictive control is an optimization-based control algorithm that solves a dynamic optimization problem over a receding time horizon of T discrete time steps. It solves the optimization problem over k=[0,..., T-1] and then applies the control input u[k=0]. The clock is then incremented and the same process is repeated over k=[1,..., T] and so on. An MPC algorithm is especially important as the electricity grid evolves to include more variable renewable energy resources such as solar and wind. A non-linear economic model predictive control algorithm is presented below [8].

Algorithm 1: Nonlinear Economic Model Predictive Control Algorithm

$$\underset{u_{k=0}}{\arg\min} \quad J = \sum_{k=0}^{T-1} x_k^T Q x_k + u_k^T W u_k^T + A x_k + B u_k \tag{9}$$

$$s.t. \quad x_{k+1} = f(x_k, u_k, \hat{d}_k) \tag{10}$$

$$x_{min} \leq x_k \leq x_{max} \tag{11}$$

$$u_{min} \leq u_k \leq u_{max} \tag{12}$$

$$x_{k=0} = \tilde{x}_0 \tag{13}$$

whereby Equation 9 represents the economic objective function, Equation 10 defines the non-linear dynamic system state equation and Equations 12, and 11 define the capacity constraints for the system inputs and states respectively. Lastly, Equation 13 defines the initial conditions. Finally, x_k, u_k, and $\hat{d}_k$ are the system state, input, and predicted disturbance at discrete time k.

C. An Economic MPC Formulation of a Multi-Period AC Optimal Power Flow

This ACOPF formulation in Section III-A lacks several features: 1.) a multi-time period formulation, 2.) ramping constraints on generation units, and 3.) an explicit description of system state. The last of these requires the most significant attention. The power flow equations in Equations 15 and 16 are derived assuming the absence of power grid imbalances and energy storage [6]. In reality, however, all power system buses are able to store energy; even if it be in relatively small quantities. Consequently, relaxing the inherent assumptions found in the traditional power flow equations introduces a state variable x_k associated with the energy stored at the power system buses during the kth time block. Naturally, limits are imposed on this state variable to reflect the physical reality and an initial state $\tilde{x}_0$ is included in the EMPC ACOPF formulation.

$$\underset{P_{Gk=0}}{\arg\min} \quad J = \sum_{k=0}^{T-1} P_{Gk}^T C_2 P_{Gk} + C_1^T P_{Gk} + C_0 \mathbf{1} \tag{14}$$

$$s.t. \quad x_{k+1} = x_k + \ldots \tag{15}$$

$$\Delta T \left(A_G P_{Gk} - A_D \hat{P}_{Dk} - Re\{diag(V_k) Y^* V_k^*\} \right)$$

$$0 = A_G Q_{Gk} - A_D \hat{Q}_{Dk} - Im\{diag(V) Y^* V^*\} \tag{16}$$

$$P_G^{min} \leq P_{Gk} \leq P_G^{max} \tag{17}$$

$$Q_G^{min} \leq Q_{Gk} \leq Q_G^{max} \tag{18}$$

$$\Delta T R_G^{min} \leq P_{Gk} - P_{G,k-1} \leq -\Delta T R_G^{max} \tag{19}$$

$$V^{min} \leq |V_k| \leq V^{max} \tag{20}$$

$$x^{min} \leq x_k \leq x^{max} \tag{21}$$

$$e_x^T \angle V_k = 0 \tag{22}$$

$$x_{k=0} = \tilde{x}_0 \tag{23}$$

Note that this EMPC ACOPF formulation is equivalent to the traditional ACOPF when $T = 0$, $x^{min} = x^{max} = 0$ and $R_G^{min}, R_G^{max} \to \infty$.

D. The ALADIN (Augmented Lagrangian Alternating Direction Inexact Newton) Algorithm

The ALADIN algorithm admits an optimization problem of the form:

$$\underset{y_i}{\arg\min} \quad J = \sum_i f(y_i) \tag{24}$$

$$s.t. \quad h_i(y_{ik}) = 0 \tag{25}$$

$$A_i y_{ik} = 0 \tag{26}$$

$$y_i^{min} \leq y_i \leq y_i^{max} \tag{27}$$

where the generic cost function J is separable with respect to N sets of decision variables y_i. Furthermore, there is a non-linear, not necessarily convex, function $h_i(y_{ik})$ for each y_i. Equation 26 is a linear consensus constraint which serves as the only coupling between the subsets of decision variables. Finally, Equation 27 adds minimum and maximum capacity constraints on the decision variables. The distributed control algorithm for solving the above optimization problem is discussed in full in [15] and proven to converge for non-linear non-convex functions h_i.

The EMPC ACOPF problem is now solved using the ALADIN algorithm as a distributed control approach. In order to do so, the decision variables $[P_{Gk}; Q_{GK}; |V_k|; \angle V_k] \forall k = [0, \ldots, T-1]$ are partitioned into several sets of decision variables $y_i = [P_{Gi}; Q_{Gi}; |V_i|; \angle V_i] \forall i = [1, \ldots, N]$; each corresponding to a predefined control area. The objective function in Equation 14 is then recast in separable form as in Equation 8 with each generator assigned to a specific control area. The state equations in Equations 15 and 16 are further partitioned by control area and constitute the non-linear, non-convex functions $h_i()$. At this point, the consensus constraints in Equation 26 serve to ensure that the flow of power going from one control area i_1 to another control area i_2 is equal and opposite to the flow of power going from i_2 to i_1. The remaining constraints of the EMPC ACOPF problem map straightforwardly to the capacity constraints of the ALADIN

optimization problem. [16] provide further background explanation of how the ALADIN optimization problem maps to a traditional ACOPF formulation.

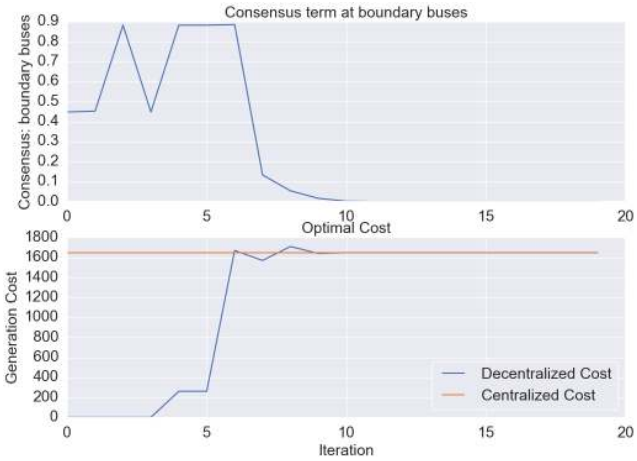

Fig. 4. This figure illustrates the convergence of the distributed optimization to the centralized objective cost value while ensuring consensus at the boundary buses.

IV. Simulation Results and Discussion

As a result of this collaboration, the team has acquired and processed the necessary system data for the City of Lebanon. The system data includes 10 feeders with a total of 5897 nodes as well as 1-minute power injection profiles for each individual feeder. However, this paper demonstrates simulation on the smallest 13 node feeder with a peak load of 6000kW. This feeder supplies electricity to the main hospital in Lebanon and as a result its demand profile is fairly flat throughout the day. Figure 3(a) depicts the 13 node feeder and Figure 3(b) represents the feeder split into two areas. Each area is comprised of several stochastic loads and a 300kW solar PV system. The substation serves as the reference bus and also a controllable generator. An MPC simulation is run every 5 minutes for a time horizon $T = 5minutes$ with a 1-minute time-step. The two areas must reach consensus as to the real and reactive power flows at the boundary between buses 4 and 5 of Figure 3. Figure 4 illustrates that consensus is reached for the boundary buses within 10 iterations and the objective cost of the ALADIN implementation also equals that of the centralized solution.

Figure 5 illustrates that the ALADIN generation closely matches the generation by the MPC implementation and that demand is met. These results not only indicate the convergence of the formulation presented in this paper but they also produce the same results as the centralized solution.

V. Conclusion

This paper has presented a distributed economic model predictive control algorithm of the ACOPF using ALADIN. It illustrates the importance of distributed algorithms for tackling the growing complexity of distribution grids. Specifically, it tests this algorithm on a 13-bus distribution grid feeder for the City of Lebanon and shows that the algorithm converges within 10 iterations and that consensus is reached with the generation for ALADIN exactly matching that of the centralized formulation.

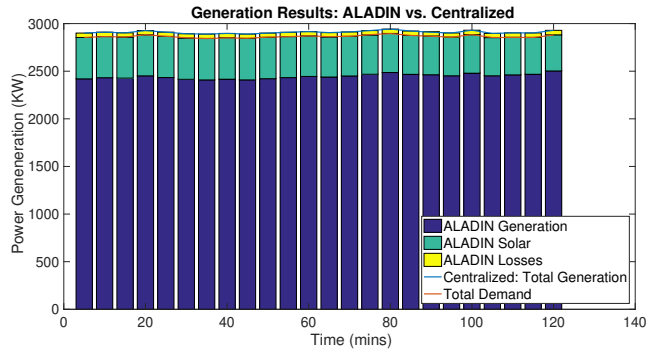

Fig. 5. ALADIN vs. centralized ACOPF generation results.

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A Distributed Economic Model Predictive Control Design for a Transactive Energy Market Platform in Lebanon, NH

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***Abstract*—The electricity distribution system is fundamentally changing due to the widespread adoption of variable renewable energy resources (VREs), network-enabled digital physical devices, and active consumer engagement. VREs are uncertain and intermittent in nature and pose various technical challenges to power systems control and operations thus limiting their penetration. Engaging the demand-side with control structures that leverage the benefits of integral social and retail market engagement from individual electricity consumers through active community-level coordination serves as a control lever that could support the greater adoption of VREs. This paper presents a Distributed Economic Model Predictive control (DEMPC) algorithm for the electric power distribution system using the augmented lagrangian alternating direction inexact newton (ALADIN) algorithm. Specifically, this DEMPC solves the Alternating Current Optimal Power Flow (ACOPF) problem over a receding time-horizon. In addition, it employs a social welfare maximization of the ACOPF to capture consumer preferences through explicit use of time-varying utility functions. The DEMPC formulation of the ACOPF applied in this work is novel as it addresses the inherent dynamic characteristics of the grid and scales with the explosion of actively controlled devices on the demand-side. The paper demonstrates the simulation methodology on a 13-node Lebanon NH distribution feeder.**

I. Introduction

In recent years, significant attention has shifted towards the effective technical and economic control of the electricity distribution system to address the complex challenge of operating electricity grids with large amounts of variable renewable energy resources (VREs) such as solar and wind. This shift in focus has been driven primarily by the rapid evolution of distribution grids to include: 1) a more active consumer base, 2) numerous smart digital devices, and 3) large amounts of distributed energy resources (DERs) [1]. Unfortunately, the ambitious goal of decarbonizing the electric power grid while enhancing its sustainable and resilient operation presents technical, economic, and regulatory challenges.

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The first of these technical challenges is that the uncertain and intermittent nature of VREs appears over multiple timescales and horizons [2]. This necessitates control techniques that capture the inter-timescale dynamics introduced to the electricity net load by VREs [1]. In that regard, numerous model predictive control (MPC) algorithms – centralized as well as distributed – have been proposed for power systems applications within the context of VRE integration. MPC is an optimal feedback control technique that uses the dynamic state of a system to predict over a finite and receding time horizon how the state of the system evolves and uses only the solution for the first time-step to update the system for the next optimization block [3]. This feedback-based closed-loop control helps to compensate for the net-load variations and stochasticity introduced by VREs in real-time operations [4]. A majority of the proposed centralized applications have focused on the dynamic economic dispatch problem [4]–[6] for systems with a high penetration of VREs or on optimal dispatch of DERs for distribution system microgrids [7], [8]. In the meantime, decentralized approaches explore similar themes as centralized ones with most focusing on the economic dispatch problem [9] or environmental dispatch with intermittent generation resources [4], [10]. However, a recent study has shown that the convergence to optimal values is not always guaranteed for decentralized approaches and that a majority of these studies neither consider ramping rates nor the impact of VREs on dispatch decisions [9].

The second of these technical challenges is that a high penetration of VREs undermines the dispatchability of the generation fleet and, therefore, requires the activation of demand side resources. Traditionally, the generation fleet comprised of large controllable thermal power plants meant to serve fairly passive loads. However, as more and more VREs are added to the electricity grid, the variability of the system net load increases significantly introducing with it dynamics that span multiple timescales. The term "net load" here is defined as the forecasted demand minus the forecasted variable generation from wind and solar. This means that in real-time operations, controllable generators must not only compensate for net load forecast errors but also provide extensive ramping capability to account for changes in variable generation due to external factors such as solar irradiance and wind speed. In the meantime, there are fewer dispatchable generators to serve this balancing role. This two-fold technical challenge greatly limits the penetration of VREs and, therefore, calls for more highly

responsive control levers. Activating the demand-side is seen as the remaining potential control lever given its evolution to include: 1) an active consumer base, 2) numerous smart energy internet of things (eIoT) devices, and 3) large amounts of distributed energy resources (DERs). These three factors increase the controllability of the demand-side paving the way for various demand-side management (DSM) solutions that can be used to shift, shed, and/or increase electricity demand in the real-time in order to balance variations in net load.

The dynamic nature of VREs also necessitates frequent decision-making which requires automated (rather than manual) solutions on distributed edge devices called the energy Internet of Things (eIoT). This frequent decision-making requires robust information and communication technologies (ICTs) that enable intelligent coordination of these distributed eIoT devices [11]. eIoT solutions must scale with the number of devices, deal with computational complexity and handle communication with other distributed devices in a timely fashion [11], [12]. Multi-agent systems (MAS) have been proposed in the literature to address the practical challenges of controlling a large number of active grid edge devices in the short time span of power grid markets [11] . Smart devices whether it is rooftop solar, electric vehicles (EVs), programmable thermostats, or battery energy storage, can coordinate as agents within a MAS to reach a global consensus that maintains power system balance or stability. In MAS approaches, agents can simplify decision making by communicating with only their neighbours to make local decisions that inform higher-level decisions [13]–[15]. This significantly reduces the amount of shared information among agents and also allows for a more robust system by eliminating the single point of failure. At the core of MAS applications are distributed control algorithms that are employed to solve local sub-problems so as to reach consensus on global objectives.

The integration of demand side resources at the grid periphery begets a third challenge; the shear number. The demand-side is comprised of millions or even billions of actively interacting cyber-physical devices that are distributed both spatially as well as functionally [11], [16]. Controlling these devices requires correspondingly distributed and scalable control algorithms [12]. Distributed control algorithms have been proposed as solutions that can scale up to such a large number of devices and still be implemented in the minute-timescale of power system markets [1]. Through effective coordination, distributed control algorithms can be used to coordinate local sub-problems to reach a global objective similar to that achieved by centralized algorithms [1].

In addition, these algorithms must respect the physical constraints of the grid which are both non-linear and non-convex. The optimal power flow (OPF) problem is among the most common optimization problems used in the economic control of the power system [17]. The OPF determines the optimal flows of power through a given electricity network to meet demand and respect operational constraints. Several variants of the OPF problem exist [18], [21], [21]; the alternating current (AC) OPF variant uses the full implementation of the "power flow equations" which, in turn, are a pseudo-steady state model of Kirchkoff's current law [17], [18], [22] and is thus, non-linear and non-convex. As one would expect, various distributed control algorithms have also been proposed for the OPF problem [23]. However, due to the non-linear, non-convex nature of the ACOPF, a majority of these algorithms seek to either linearize the ACOPF or use other relaxation techniques such as semi-definite programming (SDP) [24], [25] or second-order cone programming (SOCP). While such mathematical simplifications have their algorithmic merits, they often fail to fully capture the complex and dynamic behaviour of distribution systems [23]. Additionally, many of the proposed algorithms such as the Alternating Direction Method of Multipliers (ADMM), Alternating Target Cascading (ATC), and Dual Ascent have practical implementation weaknesses that make them unreliable when applied to large-scale applications [23]. The most common of these algorithms is the ADMM which has been widely studied in the literature in its application to the electric power grid [26], [27]. Unfortunately, recent studies have shown that the convergence of the ADMM depends highly on the choice of tuning parameters in convex spaces and is all-together not guaranteed in non-convex spaces such as the ACOPF [23]. In recent years, the Augmented Lagrangian Alternating Direction Inexact Newton (ALADIN) algorithm has been proposed in the literature as not just an alternative to the ADMM but also as a solution with better convergence guarantees even for non-convex applications such as the ACOPF [28], [29].

To be successful on a practical level, in addition to the technical challenges above, the distributed control algorithm must be implemented within an appropriate commercial and regulatory framework. Community choice aggregation (CCA) represents one such framework, and is authorized in California, Massachusetts, New York, New Jersey, Illinois, Ohio, Rhode Island and New Hampshire [30]. It is a policy that allows local governments (e.g. towns, cities and counties) to become the default electricity provider and enroll customers within their municipal boundaries that are currently on utility basic service on an opt-out basis [30]. CCAs compete on the basis of electricity procurement and retail innovation by offering consumers access to a broader portfolio of electric products, often at more competitive prices than those traditionally offered by utilities [30], [31]. CCAs are thus naturally incentivized to facilitate retail demand flexibility and the intelligent management of distributed energy to create revenue streams in new ways, by integrating these assets into wholesale market operations, the CCAs portfolio risk management, and distribution company network planning and operations. CCAs are, therefore, also incentivized to advocate for the regulatory reforms necessary to value and monetize Distributed Energy Resources in ways that account for their temporal and geographic attributes, and to expand data interchange and market access for innovative third-party companies. CCAs in certain states, most notably in California, have consequently focused on expanding retail programs and third-party customer services, and engaged in multi-sectoral decarbonization planning and local infrastructure development (e.g. microgrids, non-wires alternatives) [**?**]. However, CCAs may face operational barriers to retail innovation due to the statutory requirement that distribution utilities continue to provide retail meter reading, data

management and consolidated billing functions [**?**]. The New Hampshire market is distinguished as the only state wherein the statutory authorities of CCAs allow for the direct provision of the aforementioned retail customer services, which are critical to enabling Transactive Energy. Consequently, CCAs in New Hampshire represent a viable commercial pathway to overcome legacy utility IT systems and implement the concept of a shared integrated grid that is characterized by: 1) integral social and retail market engagement from electricity consumers, 2) the digitization of energy resources with the eIoT, and 3) widespread community-level coordination [32]. Towards this end, the City of Lebanon and other interested municipalities are drafting a Joint Power Agreement [**?**] to create an agency called "Community Power New Hampshire" [**?**] that will offer operational services to all CCAs on a statewide basis, and have already begun engaging in regulatory proceedings to create the market and control structures necessary to enable the efcient and low-cost exchange of energy data, products and services[1].

To increase consumer participation, CCAs must provide grid services that engage consumers and allow for the expression of their preferences. Typically, the bulk of consumers at the distribution system are residential homes. These consumers generally represent small loads and are driven by factors such as comfort, ease of use, and cost. This naturally demands market and control structures within CCAs that ultimately enable the efficient, and low-cost exchange of electricity products and services among consumers. These market and control structures must recognize that the value of electricity demand changes not just with quantity but also with the time of day. For instance, a commercial supermarket may be unwilling to shed 1kw of consumption for refrigeration at 7am as they are opening but could shed 1kw for laptop computers in the middle of the day after their batteries have been charged. Similarly, someone with a set routine may be willing to pay more for a hot-water shower in the morning than for the same shower in the afternoon. Given the time and usage value of electricity, transactive energy market models implemented by CCAs must capture the social benefits to consumers by explicitly implementing time-varying utility functions.

A. Contribution

Given these many technical, economic, and regulatory considerations, this paper develops a distributed transactive energy control system for the economic control of an electric power distribution system. It offers several key novel features relative to the existing literature. (1) Unlike the traditional single time step ACOPF problem based upon algebraic constraints, this work recasts the ACOPF formulation into an economic MPC with a finite look-ahead time horizon and explicit state variables. Consequently, the system proactively responds to the variability of the net load while controlling the energy stored within the distribution system. (2) The objective function in this work minimizes social welfare and incentivizes demand-side participants to have elastic behavior. (3) Demand-side utility functions applied in this study are also explicitly time-varying to account for consumer's preferences changing over the course of the day. (4) To account for the potential explosion of active devices at the grid's periphery, the EMPC problem is implemented as a multi-agent control system based on the ALADIN algorithm which has been proven to converge to a local minimizer even for nonlinear, non-convex constraints such as those presented by the ACOPF equations. (6) Finally, the DEMPC is tested on a 13-bus feeder from the City of Lebanon, NH in which controllable demand, controllable generation, stochastic generation and stochastic demand resources have been added.

[1]Refer to filings submitted by the City of Lebanon and the Local Government Coalition in NH PUC Docket 19-197. Available online: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197.html

B. Outline

The rest of this paper is organized as follows: In Section II-A, the ACOPF problem, in its generic form, is presented. Section II-B introduces a generic formulation of economic MPC problem. Section III-A outlines the ACOPF problem reformulated as an economic MPC with a social welfare minimization to capture consumer preferences. Section III-B then introduces the ALADIN algorithm and discusses its application to the previously mentioned EMPC ACOPF model. Section IV numerically demonstrates the convergence of ALADIN to the EMPC-ACOPF model for a 13-bus feeder for the City of Lebanon, NH and provides a discussion of the results. Finally, the paper is concluded in Section V.

II. Background

A. The AC Optimal Power Flow Problem

The ACOPF calculates the steady-state flows of power within any given electrical network. It is comprised of an objective function typically a generation cost minimization and is constrained by generation capacity limits, voltage magnitude limits, and power flow constraints. The traditional ACOPF formulation is presented below:

$$min \quad C(P_{GC}) = P_{GC}^T C_2 P_{GC} + C_1^T P_{GC} + C_0 \mathbf{1} \tag{1}$$

$$s.t. \quad A_{GC} P_{GC} - A_{DS} \hat{P}_{DS} = Re\{diag(V) Y^* V^*\} \tag{2}$$

$$A_{GC} Q_{GC} - A_{DS} \hat{Q}_{DS} = Im\{diag(V) Y^* V^*\} \tag{3}$$

$$P_{GC}^{min} \leq P_{GC} \leq P_{GC}^{max} \tag{4}$$

$$Q_{GC}^{min} \leq Q_{GC} \leq Q_{GC}^{max} \tag{5}$$

$$V^{min} \leq |V| \leq V^{max} \tag{6}$$

$$e_x^T \angle V = 0 \tag{7}$$

The following notations are used in this formulation:

GC	index for controllable generators
DS	index for traditional demand units
C_2, C_1, C_0	quadratic, linear, and fixed cost terms of the generation fleet
e_x	reference angle elementary basis vector
P_{GC}, Q_{GC}	active/reactive power generation
$\hat{P}_{DS}, \hat{Q}_{DS}$	total forecasted active/reactive demand
$P_{GC}^{min}, P_{GC}^{max}$	min/max active generation limits
$Q_{GC}^{min}, Q_{GC}^{max}$	min/max reactive generation limits
V^{min}, V^{max}	min/max voltage limits at buses

Y	bus admittance matrix
V	bus voltages
N_G	number of generators
A_{GC}	generator-to-bus incidence matrix
A_{DS}	load-to-bus incidence matrix

Equation 1 represents the quadratic generation cost function. Note that C_2 is a diagonal matrix and so the generation cost objective function is separable by generator. This cost function may be equivalently written as:

$$C(P_G) = \sum_{g \in G} c_{2g} P_g^2 + c_{1g} P_g + c_{0g} \tag{8}$$

Equations 2 and 3 define the active and reactive power flow constraints at a bus respectively. While Equations 4, 5, and 6 represent the active power generation, reactive power generation and bus voltage limits. Finally, 7 sets the voltage angle of the chosen reference bus(es) to 0.

B. A Generic Non-linear Economic MPC Formulation

MPC is an optimization-based control algorithm that solves a dynamic optimization problem over a receding time horizon of T discrete time steps. The solution to the optimization problem is computed over k=[0,..., T-1] and the solution for $k = 0$ is applied to the control input u[k=0]. The clock is then incremented and the same process is repeated over k=[1,..., T] and so on. A generic non-linear economic model predictive control algorithm is presented below [3].

$$\underset{u_{k=0}}{\arg\min} \quad J = \sum_{k=0}^{T-1} x_k^T Q x_k + u_k^T W u_k^T + A x_k + B u_k \tag{9}$$

$$s.t. \quad x_{k+1} = f(x_k, u_k, \hat{d}_k) \tag{10}$$

$$u_{min} \leq u_k \leq u_{max} \tag{11}$$

$$x_{min} \leq x_k \leq x_{max} \tag{12}$$

$$x_{k=0} = \tilde{x}_0 \tag{13}$$

$\hat{d}_k$	predicted disturbance at discrete time k
x_k, u_k	system states and inputs at time k
x^{min}, x^{max}	min/max system state limits
u^{min}, u^{max}	min/max system input limits

whereby Equation 9 represents the economic objective function, Equation 10 defines the non-linear dynamic system state equation while Equations 11, and 12 define the capacity constraints for the system inputs and states respectively. Lastly, Equation 13 defines the initial conditions.

III. Methodology and Simulation Setup

A. An Economic MPC Formulation of a Multi-Period AC Optimal Power Flow

The ACOPF formulation in Section II-A lacks several features: 1.) a multi-time period formulation, 2.) ramping constraints on generation units, 3.) controllable demand and stochastic generation units , 4) a time-varying demand-side utility function, and 5) an explicit description of system state. The last of these requires the most significant attention. The power flow equations in Equations 17 and 18 are derived assuming the absence of power grid imbalances and energy storage [17]. In reality, however, all power system buses are able to store energy; even if it be in relatively small quantities. Consequently, relaxing the inherent assumptions found in the traditional power flow equations introduces a state variable x_k associated with the energy stored at the power system buses during the kth time block. Naturally, limits are imposed on this state variable to reflect the physical reality and an initial state $\tilde{x}_0$ is included in the EMPC ACOPF formulation.

$$\underset{P_{GCk=0}}{\arg\min} \; J = \sum_{k=0}^{T-1} \left[C_{GC}(P_{GCk}) + C_{DCk}(P_{VGk}) \right] \tag{14}$$

$$P_{VGk} = \hat{P}_{DCk} - P_{DCk} \tag{15}$$

$$Q_{VGk} = \hat{Q}_{DCk} - Q_{DCk} \tag{16}$$

$$\begin{aligned} s.t. \quad x_{k+1} = x_k + \Delta T \big(& A_{GC} P_{GCk} + \\ & \ldots A_{GS} \hat{P}_{GSk} + A_{DC} P_{VGk} - A_{DS} \hat{P}_{DSk} - \\ & \ldots Re\{diag(V_k) Y^* V_k^*\} \big) \end{aligned} \tag{17}$$

$$\begin{aligned} 0 = A_{GC} Q_{GCk} + A_{DC} Q_{VGk} - \\ \ldots A_{DS} \hat{Q}_{DSk} - Im\{diag(V) Y^* V^*\} \end{aligned} \tag{18}$$

$$P_{GC}^{min} \leq P_{GCk} \leq P_{GC}^{max} \tag{19}$$

$$P_{VGk}^{min} \leq P_{VGk} \leq P_{VG}^{max} \tag{20}$$

$$Q_{VGk}^{min} \leq Q_{VGk} \leq Q_{VG}^{max} \tag{21}$$

$$Q_{GC}^{min} \leq Q_{GCk} \leq Q_{GC}^{max} \tag{22}$$

$$\Delta T R_{GC}^{min} \leq P_{GCk} - P_{GC,k-1} \leq \Delta T R_{GC}^{max} \tag{23}$$

$$V^{min} \leq |V_k| \leq V^{max} \tag{24}$$

$$x^{min} \leq x_k \leq x^{max} \tag{25}$$

$$e_x^T \angle V_k = 0 \tag{26}$$

$$x_{k=0} = \tilde{x}_0 \tag{27}$$

GS	stochastic generators index
DC	index for controllable demand units
$\mathbb{A}_{DCk}, \mathbb{B}_{DCk}, \mathbb{C}_{DCk}$	quadratic, linear, fixed cost terms of controllable demand at time k.
$R_{GC}^{min}, R_{GC}^{max}$	max/min generation ramp limits
P_{GCk}, Q_{GCk}	active/reactive controllable generation at k
P_{GSk}	active stochastic generation at time k
$\hat{P}_{DSk}, \hat{Q}_{DSk}$	active/reactive demand forecast at time k
$\hat{P}_{DCk}, \hat{Q}_{DCk}$	active/reactive forecasted controllable demand at discrete time k
P_{DCk}, Q_{DCk}	active/reactive dispatched controllable demand at discrete time k
x_{k+1}	system state at time $k+1$
ΔT	time step of the optimization
A_{GS}, A_{DC}	stochastic generator-to-bus & controllable load-to-bus incidence matrices

Note that this EMPC ACOPF formulation is equivalent to the traditional ACOPF when $T = 0$, $x^{min} = x^{max} = 0$ and $R_G^{min}, R_G^{max} \to \infty$. The objective function has also been modified to minimize the overall cost of controllable generation and the

cost of virtual generation for T discrete time-steps. Notice that the cost of controllable generation remains the same as before and is given by:

$$C_{GC} = P_{GCk}^T C_2 P_{GCk} + C_1^T P_{GCk} + C_0 \mathbf{1}$$

Similarly, the cost of virtual generation follows a quadratic form as that of controllable generation and defined as follows:

$$C_{DC} = (\hat{P}_{DCk} - P_{DCk})^T \mathbb{A}_{DCk} (\hat{P}_{DCk} - P_{DCk}) + \ldots \\ \mathbb{B}_{DCk}^T (\hat{P}_{DCk} - P_{DCk}) + \mathbb{C}_{DCk} \mathbf{1}$$

Whereby the coefficients $\mathbb{A}_{DCk}$, $\mathbb{B}_{DCk}$, and $\mathbb{C}_{DCk}$ vary in time to reflect consumer preferences at various points during the day. In addition to these changes, two new energy resources are introduced namely, controllable demand $(\hat{P}_{DCk} - P_{DCk})$ and stochastic generation $\hat{P}_{GSk}$. The virtual generation $(\hat{P}_{DCk} - P_{DCk})$ is also subject to capacity limits given by Equation 20. To eliminate baseline errors associated with virtual power plants [33], the capacity limits of virtual generation are set as 20% of forecasted stochastic demand for each demand node.

B. The ALADIN (Augmented Lagrangian Alternating Direction Inexact Newton) Algorithm

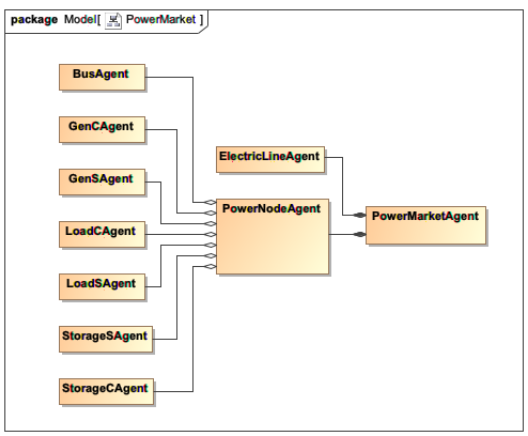

Fig. 1. Area agent architecture.

The ALADIN algorithm admits an optimization problem of the form:

$$\arg\min_{y_i} \quad J = \sum_i f(y_i) \tag{28}$$

$$s.t. \quad h_i(y_{ik}) = 0 \tag{29}$$

$$A_i y_{ik} = 0 \tag{30}$$

$$y_i^{min} \leq y_i \leq y_i^{max} \tag{31}$$

where the generic objective function J is separable with respect to N sets of decision variables y_i. Furthermore, there is a non-linear, not necessarily convex, function $h_i()$ for each y_i. Equation 30 is a linear consensus constraint which serves as the only coupling between the subsets of decision variables. Finally, Equation 31 adds minimum and maximum capacity constraints on the decision variables. The distributed control algorithm for solving the above optimization problem is discussed in full in [29] and proven to converge even for cases where the functions h_i are non-linear and/or non-convex.

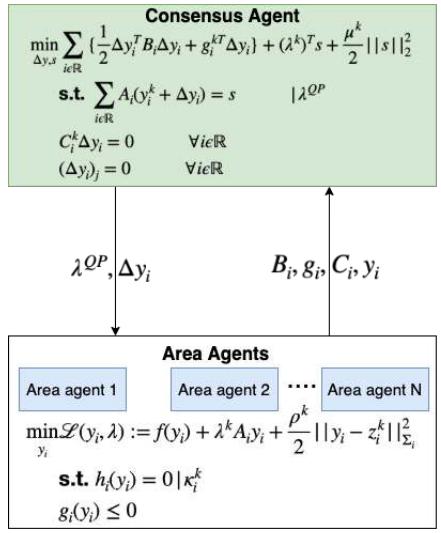

Fig. 2. ALADIN agent architecture.

The distributed ALADIN algorithm is best summarized by Figure 2. The algorithm is comprised of two steps, a fully distributed step where area agents compute the solution to a non-linear optimization sub-problem for their respective control area. Each control area represents a power system area with a local agent architecture as the one depicted in Figure 1. The sub-problem in a given control area is obtained by rearranging Equations 28, 29, 30, and 31 as shown in Figure 2.

The area agents then share their hessians, jacobians, gradients, and local solutions with the consensus agent who then determines the updates (Δy_i and λ_{QP}) for the dual and primal variables by solving the quadratically-constrained problem (QCP) shown in Figure 2. Notice that the role of the consensus agent may be carried out by a centralized facilitator or by any of the local area agents. The dual and primal variables are updated according to equations 32 and 33. In some cases, a line search is carried out to determine the update rate for coefficients $\alpha_1, \alpha_2,$ and α_3 otherwise, $\alpha_1 = \alpha_2 = \alpha_3 = 1$.

$$z^{k+1} \leftarrow z^k + \alpha_1^k (y^k - z^k) + \alpha_2^k \Delta y^k \tag{32}$$

$$\lambda^{k+1} \leftarrow \lambda^k + \alpha_3^k (\lambda^{QP} - \lambda^k) \tag{33}$$

Two penalty parameters ρ and μ are employed in this algorithm for the local sub-problems and the consensus QCP respectively. These parameters are updated according to Equation 34. r_ρ and r_μ are constants that are chosen specifically to aid in updating the penalty parameters.

$$\rho^{k+1}(\mu^{k+1}) = \begin{cases} r_\rho \rho^k \quad (r_\mu \mu^k) & \text{if } \rho^k < \bar{\rho} \ (\mu^k < \bar{\mu}) \\ \rho^k (\mu^k) & \text{otherwise} \end{cases} \tag{34}$$

The EMPC ACOPF problem presented in Section III-A is now solved using the ALADIN algorithm as a distributed control approach. In order to do so, the decision variables $y = [P_{Gk}; Q_{Gk}; |V_k|; \angle V_k] \quad \forall k = [0, \ldots, T-1]$ are partitioned into several sets of decision variables $y_i = [P_{Gi}; Q_{Gi}; |V_i|; \angle V_i] \quad \forall i = [1, \ldots, N]$; each corresponding to a predefined control area i. The objective function in Equation 14 is then recast in a separable form as in Equation 8 with each generator assigned

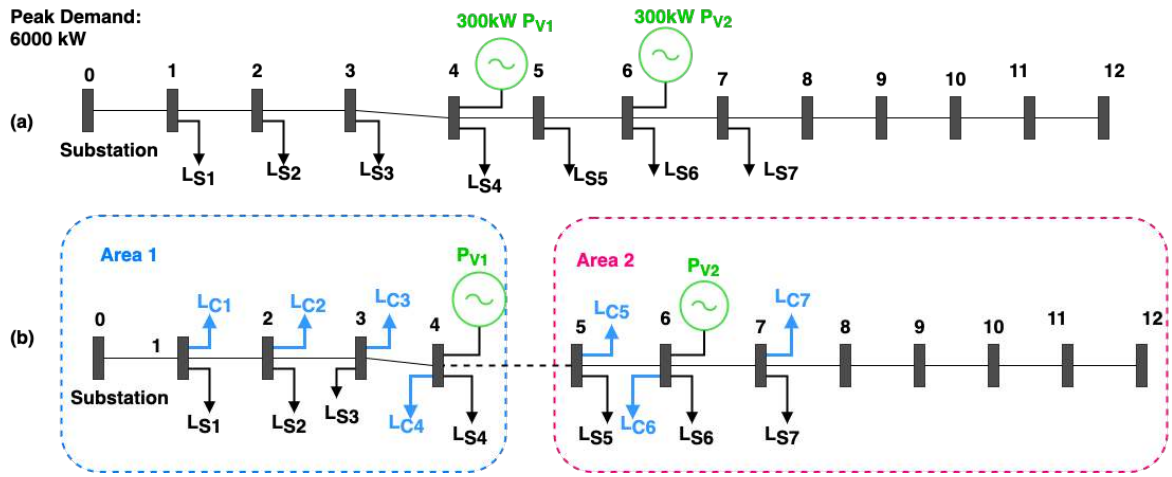

Fig. 3. 13-bus distribution feeder for the City of Lebanon NH, with a peak demand of 6000kW, 2 300kW solar PV plants and 7 conventional loads.

to a specific control area. The state equations in Equations 17 and 18 are further partitioned by control area and constitute the non-linear, non-convex functions $h_i()$. At this point, the consensus constraints in Equation 30 serve to ensure that the power flowing from one control area i_1 to another control area i_2 is equal and opposite to the power flowing from i_2 to i_1. The remaining constraints of the EMPC ACOPF problem map straightforwardly to the capacity constraints of the ALADIN optimization problem. [34]–[36] provide further background explanation of how the ALADIN optimization problem maps to a traditional ACOPF formulation and [28] discusses the general ALADIN algorithm including a line search implementation.

IV. Numerical Demonstration of Convergence

The goal of this section is to demonstrate the distributed economic model predictive control design as a potential trans-active energy market platform for the City of Lebanon, NH. More specifically, the DEMPC is numerically demonstrated on real-life data from a 13-bus feeder for the City of Lebanon distribution grid shown in Figure 3. (Given the sensitivity of the topology and load data from the local utility, it has not been shared in this publication.) Figure 3(a) represents the original feeder with 7 conventional loads $[L_{S1} \rightarrow L_{S7}]$ that account for an annual peak load of 6000kW. For the purposes of this study, two solar photo-voltaic (PV) plants each with a capacity of 300kW are placed on nodes 4 and 6. For a distributed simulation, the 13-bus feeder is broken down into two areas as shown in Figure 3(b). Area 1 is comprised of Nodes 0 to 4 while Area 2 is comprised of Nodes 5 through 12. To incentivize demand-side participants, virtual power plants $[L_{C1} \rightarrow L_{C7}]$ whose maximum capacity is 20% of the total stochastic demand at the node are added. These plants represents the amount of available controllable demand at each consumer node in time. Note that the maximum capacity limit of the virtual power plants $[L_{C1} \ldots L_{C7}]$ changes with time and follows the stochastic demand profile at the individual node. To reach a consensus, the boundary nodes between nodes 4 and 5 must reach the same values for active and reactive power flows as well as angles and voltages for all time steps of the MPC. Additionally, the value of the objective must converge to that of the centralized solution within some error margin. Finally, to test the methodology, an MPC simulation is run every 5-minutes with a 25-min horizon and 5-min time step. Results are presented for a single day. The parameter values used for this study are based on those presented in [34] and are tweaked as needed. In this study, the two ALADIN penalty parameters ρ and μ are as follows: $\rho = [1e2 \rightarrow 1e5]$ and $\mu = [1e3 \rightarrow 1e5]$. ρ is incremented by a factor of 1.5 after each iteration while μ is incremented by a factor of 2. A line search was not implemented for this demonstration, however, for more complex applications, a line search is recommended to determine the dual and primal update steps [28]. The active and reactive demand and net load profiles used in this study are shown in Figure4(a). The time-varying locational marginal prices (LMPs) that are applied for the virtual power plants are shown in Figure4(c). Finally, Figure4(c) represents the total controllable demand available in the system.

Figure 5(a) compares the active generation profile from the ALADIN EMPC implemention to that of the centralized EMPC approach. As seen in Figure 5(a) the ALADIN solution meets demand and results in a final generation profile that matches that of the centralized solution. The active power losses account for approximately 4-6% of the total demand on the feeder. This result is typical for distribution systems. A comparison of the optimal cost for the centralized versus the distributed approach (illustrated by Figure 5(b))shows similar values with a maximum deviation of 0.0212% from the centralized solution. These results indicate that the solution of the distributed approach closely matches that of the centralized approach with small variations that can be resolved with better parameter estimation and a line search. Finally, Figure 5(c) shows the reactive power generation profile. Similarly, this figure illustrates that the reactive power demand on the system is met and that the centralized and distributed solutions closely match.

V. Conclusion

This paper has presented the mathematical formulation for the ACOPF as an EMPC in the context of managing distribution electricity grids with high penetrations of VREs as well as controllable demand. Inherent to the formulation is an introduction of a non-zero energy storage quantity at

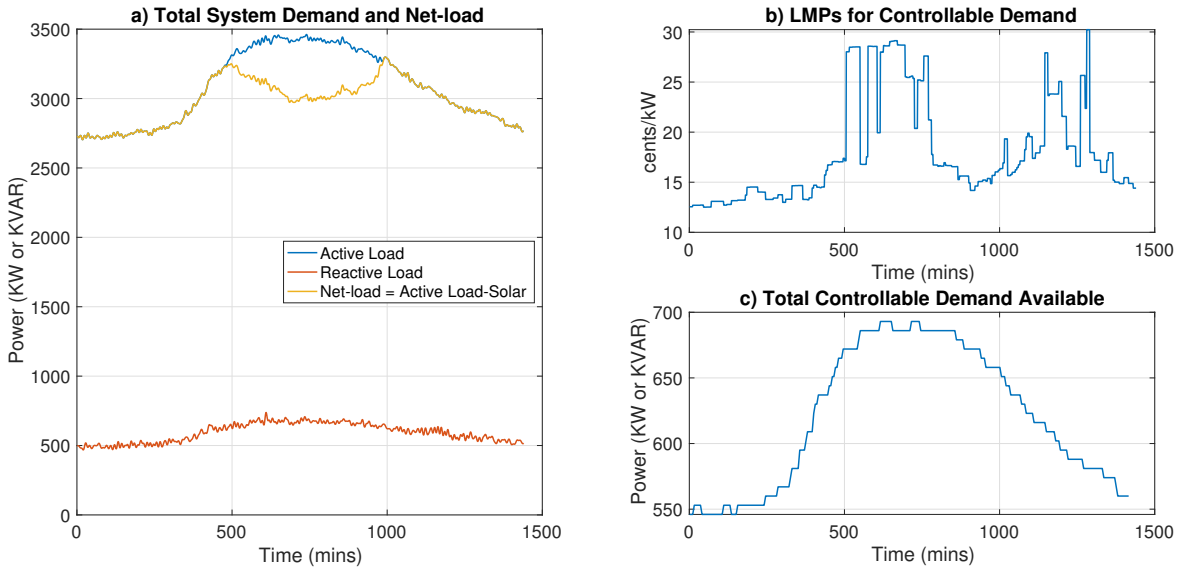

Fig. 4. Demand and net load profiles, consensus at boundary buses and convergence of the objective cost value to that of the centralized solution.

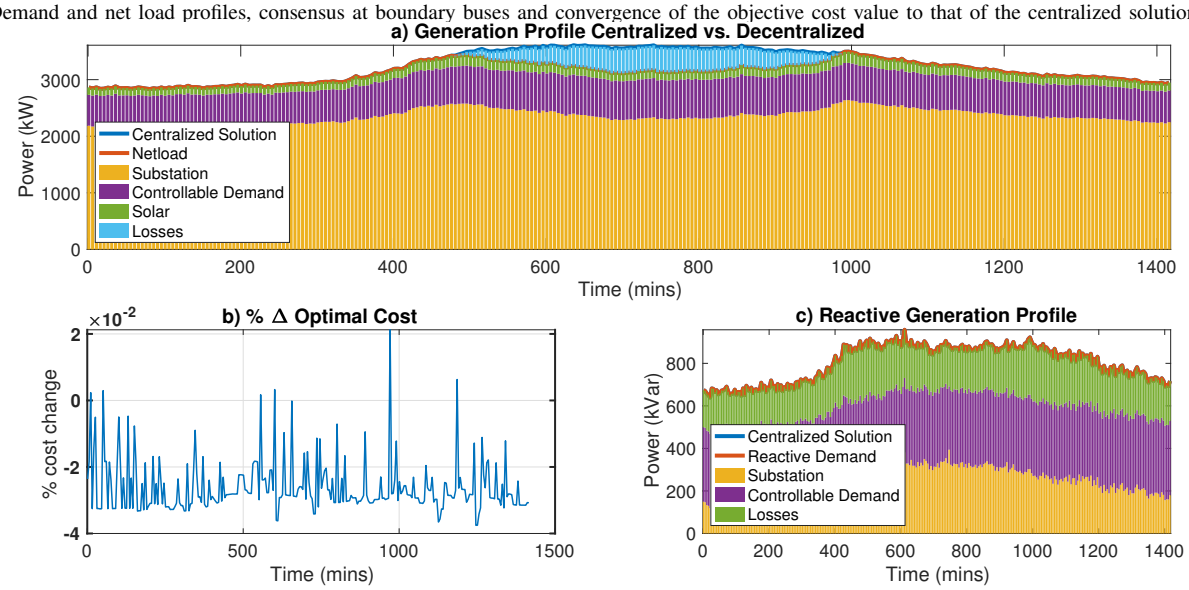

Fig. 5. Generation profile comparing the centralized vs. the distributed case and the overall change in optimal cost

each bus as a state variable with capacity constraints. This EMPC ACOPF formulation is then recast as a distributed control problem for which the ALADIN algorithm is applied. The paper then demonstrates the methodology on a 13-bus feeder for the City of Lebanon, NH comprising of four types of energy resources, controllable demand and generation, and stochastic demand and generation. The distributed solution is shown to converge to a solution that meets demands and matches the centralized solution. Finally, optimal cost results of the distributed approach closely match those of the centralized solution within a small margin of error.

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Samuel Golding Samuel V. Golding, President of Community Choice Partners Inc., has been a technical consultant and campaign strategist in the Community Choice Aggregation (CCA) industry for over a decade. He is recognized as a pioneer of the joint action governance structures and advanced operating models that enable CCAs to animate retail markets and develop regulatory frameworks conducive to demand flexibility, particularly in California and New Hampshire. He received his B.A. in International Political Economy in 2007 from The Colorado College.

Tad Montgomery Tad Montgomery is the Energy and Facilities Manager for the city of Lebanon, NH. His responsibilities include assisting the city in meeting its greenhouse gas reduction goals in line with the Paris Climate Accord. Projects include adoption of 800 kW of solar power, development of the Lebanon Community Power municipal aggregation program, thermal energy conservation throughout city buildings, and demand reduction in the big electric accounts at the water and wastewater plants. He has an B.S. in Ceramic Engineering from Alfred University and an M.S. in Environmental Systems Analysis (abd) from Humboldt State University.

Clifton Below Clifton Below is the Assistant Mayor of the City of Lebanon and Chair of its Energy Advisory Committee. He formerly served 6 years as a Public Utilities Commissioner for NH and 12 years in the NH House and Senate. He earned his B.A. from Dartmouth College in 1980 and a Master of Science in Community Economic Development from Southern NH University in 1985.

Amro M. Farid Prof. Amro M. Farid is currently an Associate Professor of Engineering at the Thayer School of Engineering at Dartmouth and Adjunct Associate Professor of computer science at the Department of Computer Science. He leads the Laboratory for Intelligent Integrated Networks of Engineering Systems (LIINES). The laboratory maintains an active research program in Smart Power Grids, Energy-Water Nexus, Energy-Transportation Nexus, Industrial Energy Management, and Integrated Smart City Infrastructures. He received his Sc. B. in 2000 and his Sc. M. 2002 in mechanical engineering from MIT and his Ph.D. degree in Engineering from the U. of Cambridge (UK).

Accelerating the Shared Integrated Grid through an eIoT eXtensible Information Model:

A Dartmouth-LIINES & EPRI Collaboration

Amro M. Farid
Associate Professor of Engineering
Adj. Assoc. Prof. of Computer Science

Thayer School of Engineering at Dartmouth

LIINES
LABORATORY FOR INTELLIGENT INTEGRATED NETWORKS OF ENGINEERING SYSTEMS
EMPOWERING YOUR NETWORK

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Invited Presentation:
Stanford University

Stanford, CA
July 15th, 2020

Presentation Abstract

The electric power system is rapidly decarbonizing with variable renewable energy resources (VREs) to mitigate rising climate change concerns. There are, however, fundamental VRE penetration limits that can only be lifted with the complementary integration of flexible demand-side resources. The implementation of such demand-side resources necessitates a ``shared integrated grid'' that is characterized by: 1) integral social engagement from individual electricity consumers 2.) the digitization of energy resources through the energy internet of things (eIoT), and 3) community level coordination. This presentation argues that an eIoT eXtensible Information Model (eIoT-XIM) is instrumental to bringing about a shared integrated grid and goes on to describe four steps to do so: 1.) develop an eIoT-XIM collaboration platform 2.) develop an eIoT-XIM consortium 3.) develop an eIoT-XIM data platform and 4.) apply the eIoT-XIM to transactive energy markets. Throughout the presentation, we will highlight New Hampshire's role towards these steps in terms of two recently passed Senate Bills 284 and 286. The former establishes a statewide, multi-use online energy data platform. The latter allows municipalities and counties to establish community power aggregators that can entirely transform retail electricity markets.

Presentation Outline

Goal: To describe the Dartmouth-LIINES and EPRI effort to conceptualize the development of an energy Internet of Things eXtensible Information Model (eIoT-XIM)

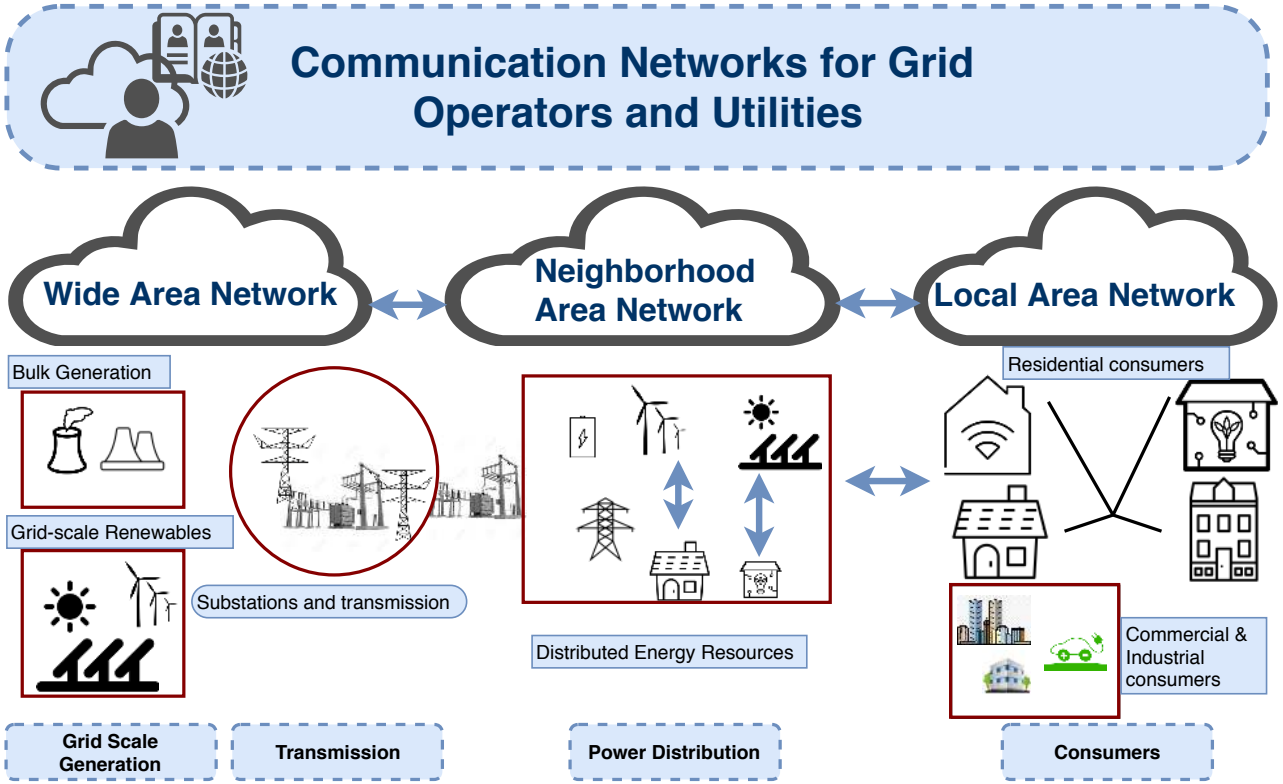
- ***Introduction:***
  - *What is an energy Internet of Things eXtensibile Information Model (eIoT-XIM) and why is it so important?*
- **Developing an eIoT-XIM Collaboration Platform**
  - *Early on, there was a deep recognition that the development of an eIoT-XIM required a collaboration platform.*
- **Developing an eIoT-XIM Consortium**
  - *Early on, there was a deep recognition that the development of an eIoT-XIM required a consortium of diverse grid stakeholders.*
- **Developing an eIoT-XIM Data Platform**
  - *An eIoT-XIM must serve a wide variety of complex use cases while remaining interoperable with large body of CIM standards.*
- **Applying an eIoT-XIM to a transactive energy blockchain simulation**
  - *To demonstrate the potential for an eIoT-XIM, we highlight how it may be applied to a transactive energy blockchain application in the City of Lebanon, NH.*

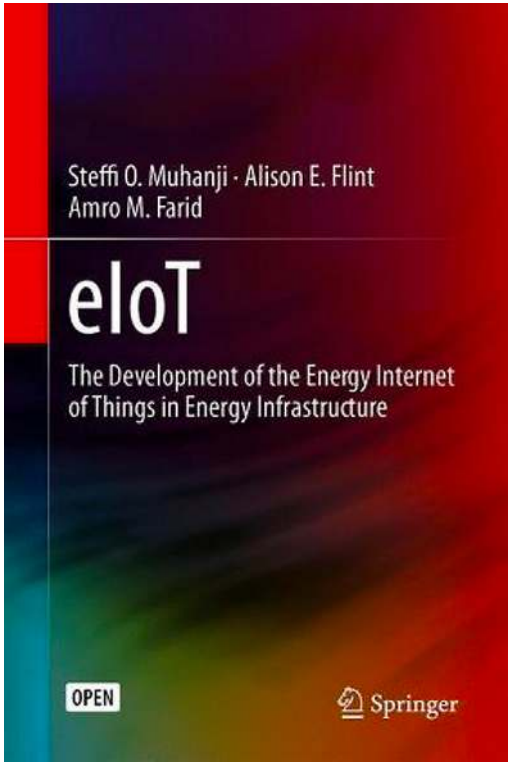
We will demonstrate the potential for collaborative IMPACT by highlighting relevant & ongoing activities in the LIINES & NH.

What is the energy Internet of Things (eIoT)?

eIoT = network-enabled energy devices in a shared economy

The Ubiquitous Energy Internet of Things





The energy Internet of Things (eIoT) appears in many forms throughout the entirety of the grid's value chain.

What is an eIoT eXtensible Information Model (XIM)?

XIM – An extensible collection of nouns and attributes that provide a common language for describing eIoT devices and how they communicate with each other on the internet

eIoT's Importance: The Sustainable Energy Transition

Past:

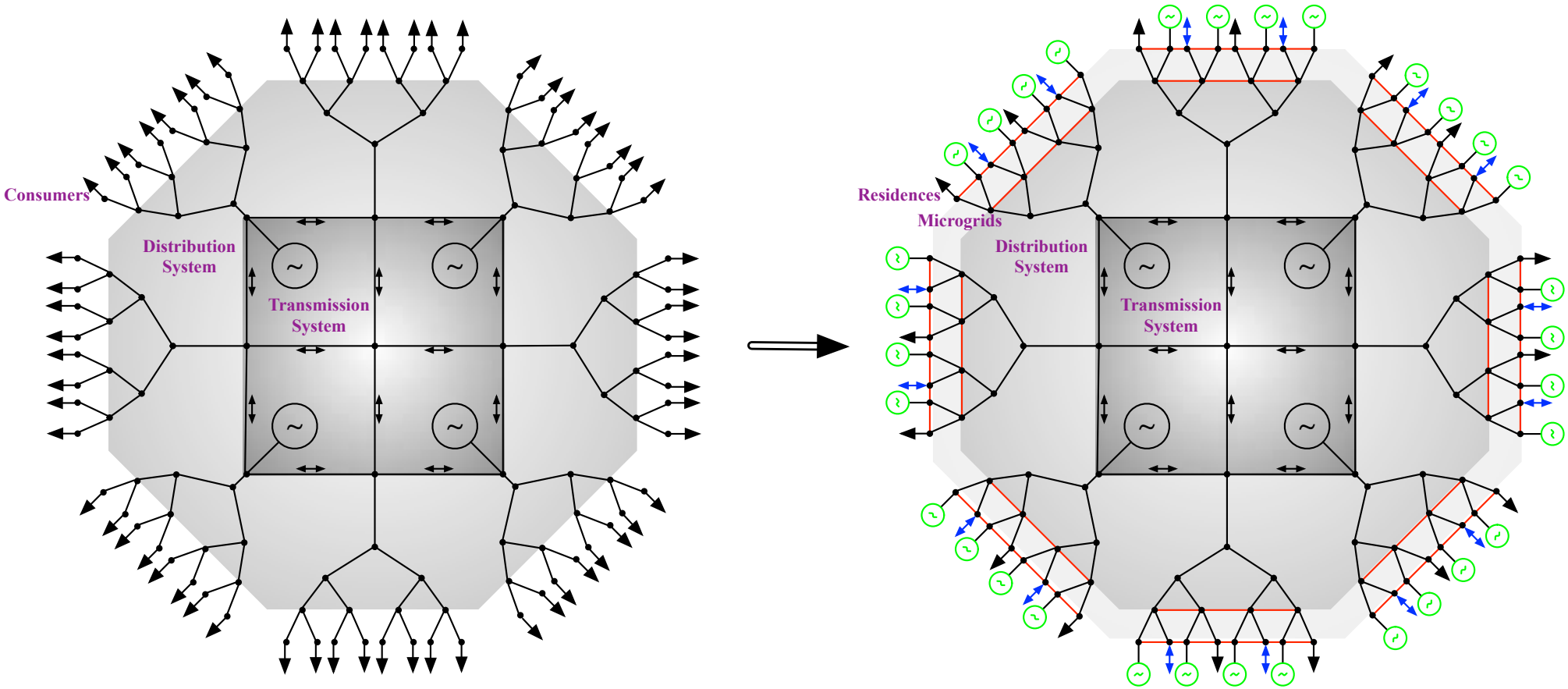
Generation/Supply	Load/Demand
Thermal Units: Few, Well-Controlled, Dispatchable, In Steady-State	Conventional Loads: Slow Moving, Highly Predictable, Always Served

Future:

	Generation/Supply	Load/Demand
Well-Controlled & Dispatchable	Thermal Units: (Potential erosion of capacity factor) ↓	eIoT-enabled Demand Side Resources: (Requires new control & market design) ↑
Stochastic/ Forecasted	Solar & Wind Generation ↑ (Can cause unmanaged grid imbalances)	Conventional Loads: ↓ (Growing & Needs Curtailment)

∴ The emergence of VRE necessitates eIoT-enabled demand side resources to maintain grid reliability, promote decarbonization, reduce operating and investment costs.

eIoT's Importance: The Transition to an Active Grid Periphery



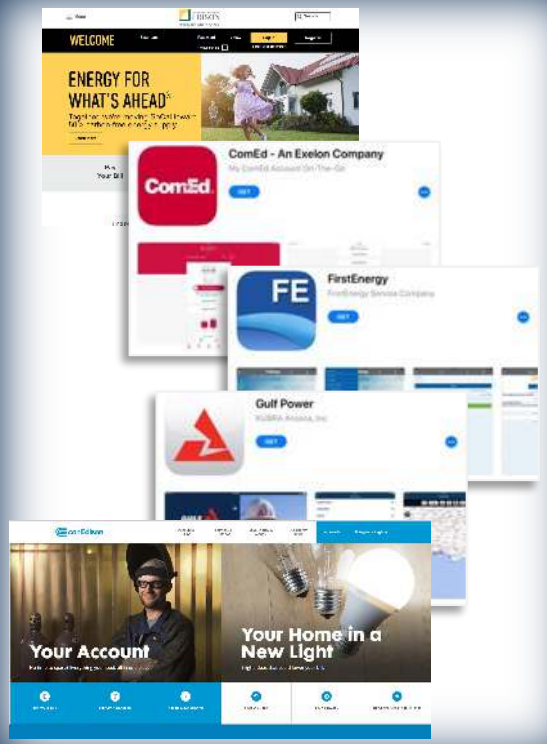
The integration of distributed energy resources at the grid's periphery implies the adoption of a plethora of network-enabled devices and appliances in an energy Internet of Things.

Imagine…A World Where Customers Are Part of the Solution

The Shared Integrated Grid

Creating a Shared Integrated Grid (#sharedgrid)

Customer Engagement



Connected Devices = Shared Economy

Community Level Coordination

∴ **eIoT-XIM enables the eIoT which in turn enables a Shared Integrated Grid!**

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- **Developing an eIoT-XIM (How?!)**
  - *An eIoT-XIM must serve a wide variety of complex use cases while remaining interoperable with large body of CIM standards.*
- **Applying an eIoT-XIM to a transactive energy blockchain simulation**
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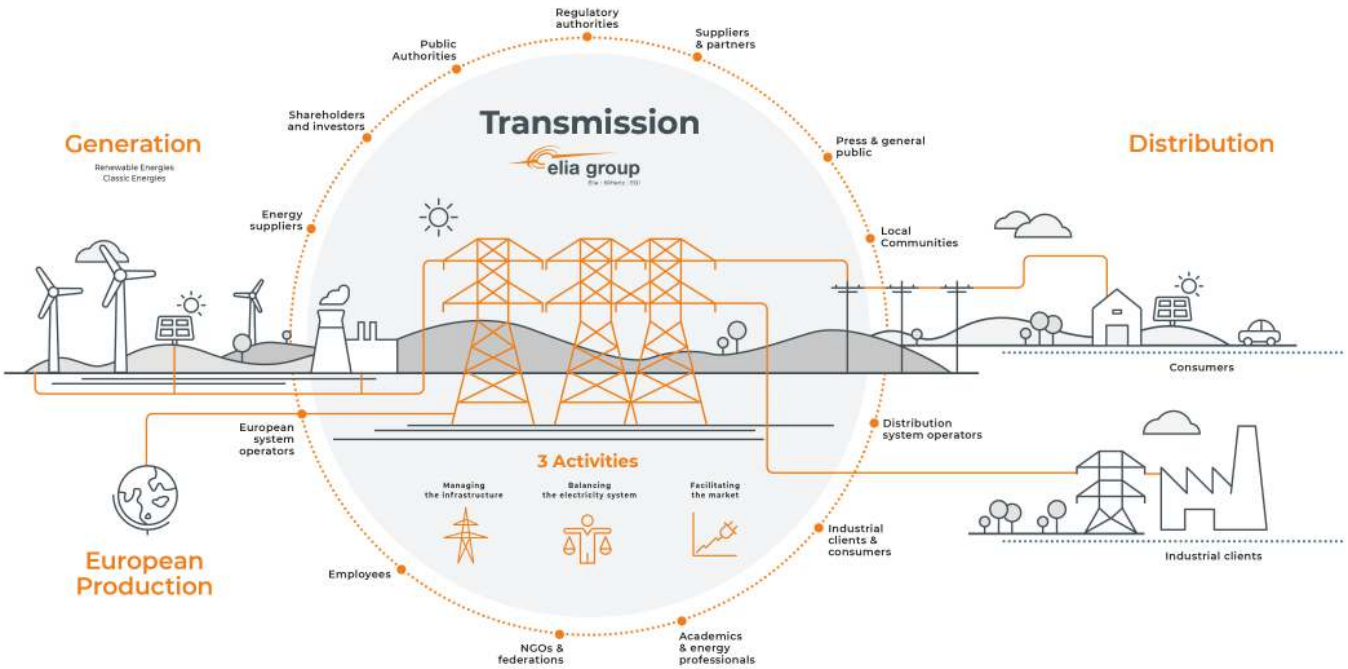
Developing an eIoT-XIM Collaboration Platform

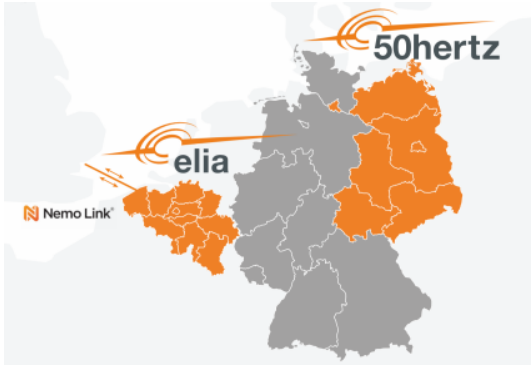
As the eIoT-XIM project progressed, it became apparent that NH already possessed several emerging *Shared Integrated Grid* collaboration platforms.

- **City of Lebanon Energy Advisory Committee** ➔ City leader in Community Power Aggregation in NH
- **Sustainable Hanover Committee** ➔ Leading Municipal Implementation of Real-Time Pricing
- **NH Community Power Coalition** ➔ Bringing together NH Cities, Towns & Counties interested in Community Power Aggregation.
- **NH PUC Community Power Aggregation Rule Making** ➔ Serves to enable the implementation of community power aggregation
- **NH PUC Statewide Multi-Use Online Energy Data Platform Docket** ➔ Serves to enable the design & implementation of a data platform

Local initiatives using existing local collaboration platforms
Many Parallel Initiatives ➔ Proves the Need for Collaborative Efforts
…but NH is not alone…

Developing an eIoT-XIM Collaboration Platform





Internet of Energy

Local Initiatives are popping up all over the world

EPRI & the Dartmouth-LIINES recognize the need for an eIoT-enabled Shared Integrated Grid Collaboration Platform

Presentation Outline

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Developing an eIoT-XIM Consortium: Community Power NH

As the eIoT-XIM project progressed, it became apparent that many NH stakeholders already wished to participate in *Shared Integrated Grid* consortiums.

Participating Municipal members:

1. Bristol (Paul Bemis)
2. Harrisville (Mary Day Mordecai & Ned Hulbert)
3. Hanover (Julia Griffin & April Salas)
4. Lebanon (Clifton Below)
5. Nashua (Doria Brown)
6. Cheshire County (Rod Bouchard)
7. Monadnock Energy Hub (Dori Drachman)

Community support members:

8. Clean Energy New Hampshire (*facilitator*: Henry Herndon)
9. Dartmouth College (*ex officio*: Dr. Amro Farid)
10. Community Choice Partners (*ex officio*: Samuel Golding)

5 Municipalities
~53,000 customers (7% of market)
~460,000 MWh / yr
~$50 million (supply)

23 Municipalities
~36,000 customers (5% of market)
~315,000 MWh / yr
~$35 million (supply)

9 Municipalities
~21,000 customers (3% of market)
~183,000 MWh / yr
~$20 million (supply)

Community Power New Hampshire already draws from a broad spectrum of NH grid stakeholders.

Developing an eIoT-XIM Consortium: NH Energy Data Platform

As the eIoT-XIM project progressed, it became apparent that many NH stakeholders already wished to participate in *Shared Integrated Grid* consortiums.

1. NH Public Utilities Commission
2. NH Office of the Consumer Advocate
3. NH Representative Kat McGhee
4. City of Lebanon
5. Town of Hanover
6. Unitil
7. Eversource
8. Liberty Utilities
9. Dartmouth-LIINES-Thayer School of Engineering
10. Dartmouth Tuck School of Business
11. Community Choice Partners
12. Clean Energy New Hampshire
13. Greentel Group
14. Mission Data
15. Deloitte Consulting
16. Utility API
17. Packetized Energy
18. Freedom Energy Logistics
19. Orr & Reno P.A
20. Mark Dean PLLC

Broad Spectrum of Engaged Grid Stakeholders:
State & Local Government, Utilities, Academia, Industry Experts, Non-Profits, Vendors, Legal Counsel

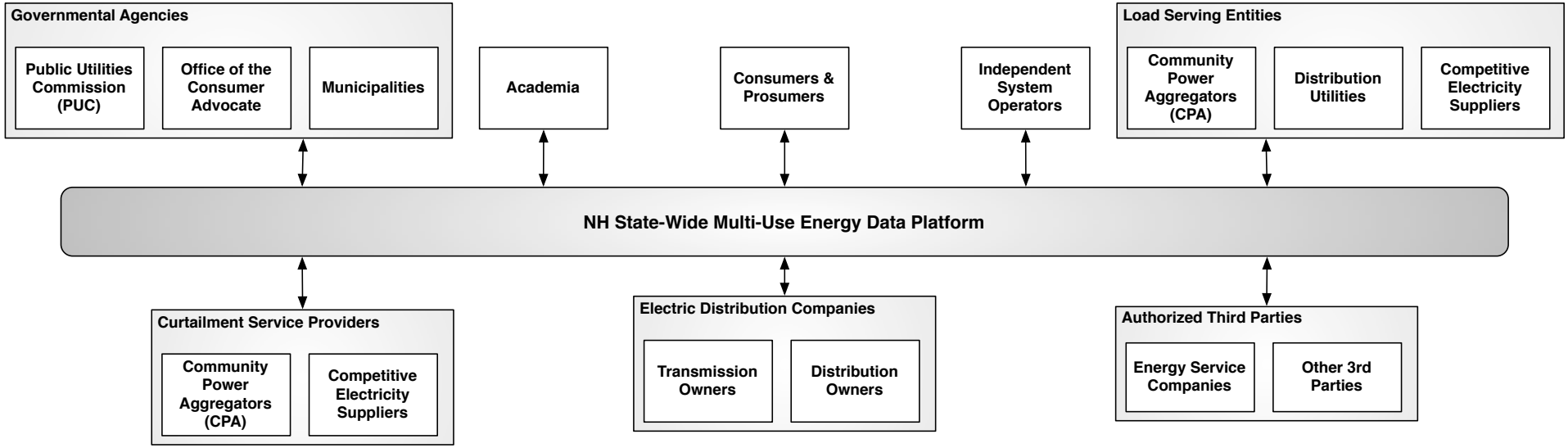
Presentation Outline

Goal: To describe the Dartmouth-LIINES and EPRI effort to conceptualize the development of an energy Internet of Things eXtensible Information Model (eIoT-XIM)

- **Introduction:**
  - *What is an energy Internet of Things eXtensibile Information Model (eIoT-XIM) and why is it so important?*
- **Developing an eIoT-XIM Collaboration Platform**
  - *Early on, there was a deep recognition that the development of an eIoT-XIM required a collaboration platform.*
- **Developing an eIoT-XIM Consortium**
  - *Early on, there was a deep recognition that the development of an eIoT-XIM required a consortium of diverse grid stakeholders.*
- ***Developing an eIoT-XIM (How?!)***
  - *An eIoT-XIM must serve a wide variety of complex use cases while remaining interoperable with large body of CIM standards.*
- **Applying an eIoT-XIM to a transactive energy blockchain simulation**
  - *To demonstrate the potential for an eIoT-XIM, we highlight how it may be applied to a transactive energy blockchain application in the City of Lebanon, NH.*

We will demonstrate the potential for collaborative IMPACT by highlighting relevant & ongoing activities in the LIINES & NH.

Envisioning a NH State-Wide Multi-Use Energy Data Platform



Q: How might we think about building such an energy data platform? What are we going to have to pay special attention to?

One Answer: Just start coding!

One Answer: Write a Request for Proposals. Outsource it to the lowest bidder!

Your Answer: _____*Write your answer in the chat box*_____

Building a Big Tent: NH Energy Data Platform Stakeholders

The building of a NH energy data platform should be viewed as a *Shared Integrated Grid* systems engineering activity.

1. NH Public Utilities Commission
2. NH Office of the Consumer Advocate
3. NH Representative Kat McGhee
4. City of Lebanon
5. Town of Hanover
6. Unitil
7. Eversource
8. Liberty Utilities
9. Dartmouth-LIINES-Thayer School of Engineering
10. Dartmouth Tuck School of Business
11. Community Choice Partners
12. Clean Energy New Hampshire
13. Greentel Group
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A Big Tent Systems Approach: Architecting the NH Energy Data Platform

Steps:

1. **Context Awareness:** Understand the legal context of deregulation (i.e. SB 284 & SB 286)
2. ***Requirements Gathering***: Identify stakeholder requirements & use cases from existing legislation, regulations, stakeholder needs. Collect from all stakeholders.
3. **Requirements Engineering:** Reconcile the stakeholder requirements & use cases into a mutually exclusive & collective exhaustive set of technical requirements. All use cases & requirements are equally valid.
4. **Quantify the Associated Benefits (in dollar terms): System Function → Benefits**
5. **Determine the Relevant Data:** For each technical requirement, assure interoperability & extensibility with existing IEC Common Information Model standards
6. **Quantify the Associated Costs (in dollar terms): System Form → Costs**
7. **Address Governance and Implementation Challenges:**

Developing a NH Energy Data Platform is a collaborative, context-aware socio-technical effort!

A Big Tent Systems Approach: A Stakeholder Access Example Requirement

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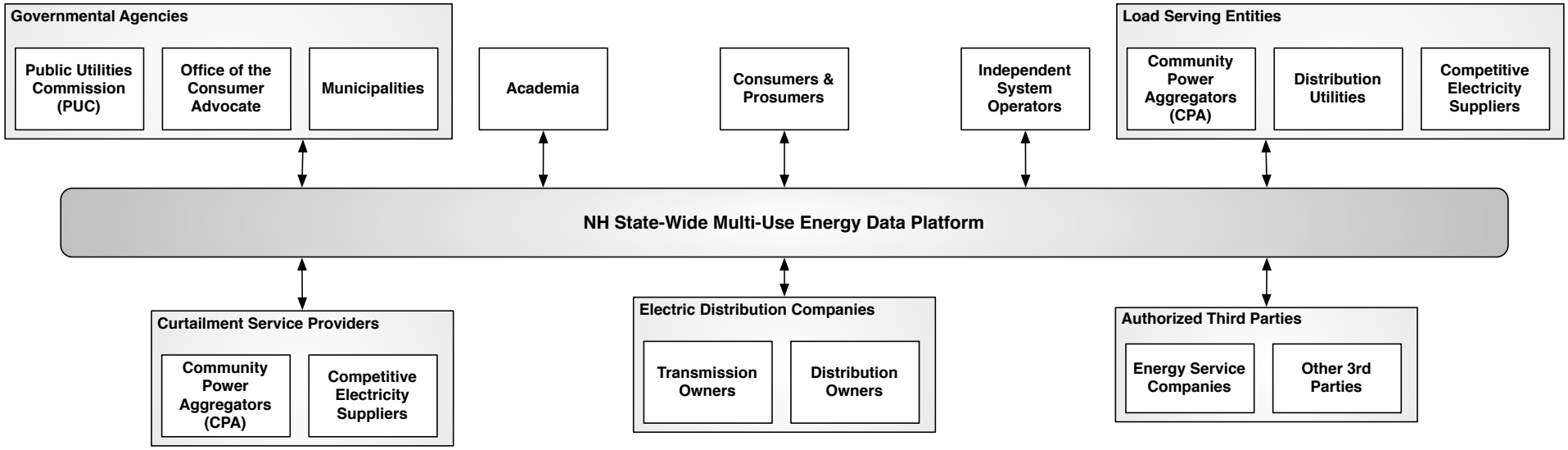

Stakeholder Access Requirement The NH State-Wide Multi-Use Energy Data Platform shall provide stakeholder-appropriate, secure, and interoperable access for each of the stakeholder categories identified above.

Make sure there is a place on the platform for all stakeholders!

A Big Tent Systems Approach: A Community Power Aggregator Example Requirement

Steps:

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RSA 53-E:3/SB 286 "[CPAs have the authority to] provide for:
(1) The supply of electric power.
(2) Demand side management.
(3) Conservation.
(4) Meter reading.
(5) Customer service.
(6) Other related services.
(7) The operation of energy efficiency and clean energy districts adopted by a municipality pursuant to RSA 53-F."

4. OPERATION OF A COMMUNITY POWER AGGREGATION PROGRAM
4.1 The data platform shall provide CPAs and customers the read, write, and append access to support the exchange of electric power services.
4.2 The data platform shall provide CPAs and customers the read, write, and append access to support the exchange of demand side management services.
4.3 The data platform shall provide CPAs and customers the read, write, and append access to support the exchange of conservation services.
4.4 The data platform shall provide CPAs and customers the read, write, and append access to support the exchange of energy efficiency services.
4.5 The data platform shall provide CPAs and customers the read, write, and append access to support customer service activities.
4.6 The data platform shall provide the CPAs, and electric utilities (as owners/operators of metering systems) access to read, write and update customers' consumption and distribution generation meter data.
4.7 The data platform shall provide customers access to read their consumption and distributed generation meter data.

Infuse the new legislation into the system requirements/use cases

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    1. Equal Validity: A hypothetical road has pedestrian, cyclist, and motorist use cases
    2. Technical Requirements: Warm & Cozy vs. {72°F, 50% Humidity}
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Managing the Complexity: Stakeholder Requirements by Life Cycle Stage

Types of Use Cases

Operations Archetype Use Case

Transactive Energy Market: Dispatchable energy resources exchange via a distribution system operator a number of kilo-watt hours (active power integrated over time) in normal operating mode at a time-varying market-clearing rate with self-scheduled energy resources (be they generators, storage resources or consumers), for the duration of 5 minutes, on a given distribution system feeder.

The Operations Improvement Archetype Use Case

Improve Energy Efficiency (Sense Energy Monitor): Homeowner monitors home electricity consumption in kilo-watt hours in normal operating mode for the duration of one month with one minute granularity.

Maintenance

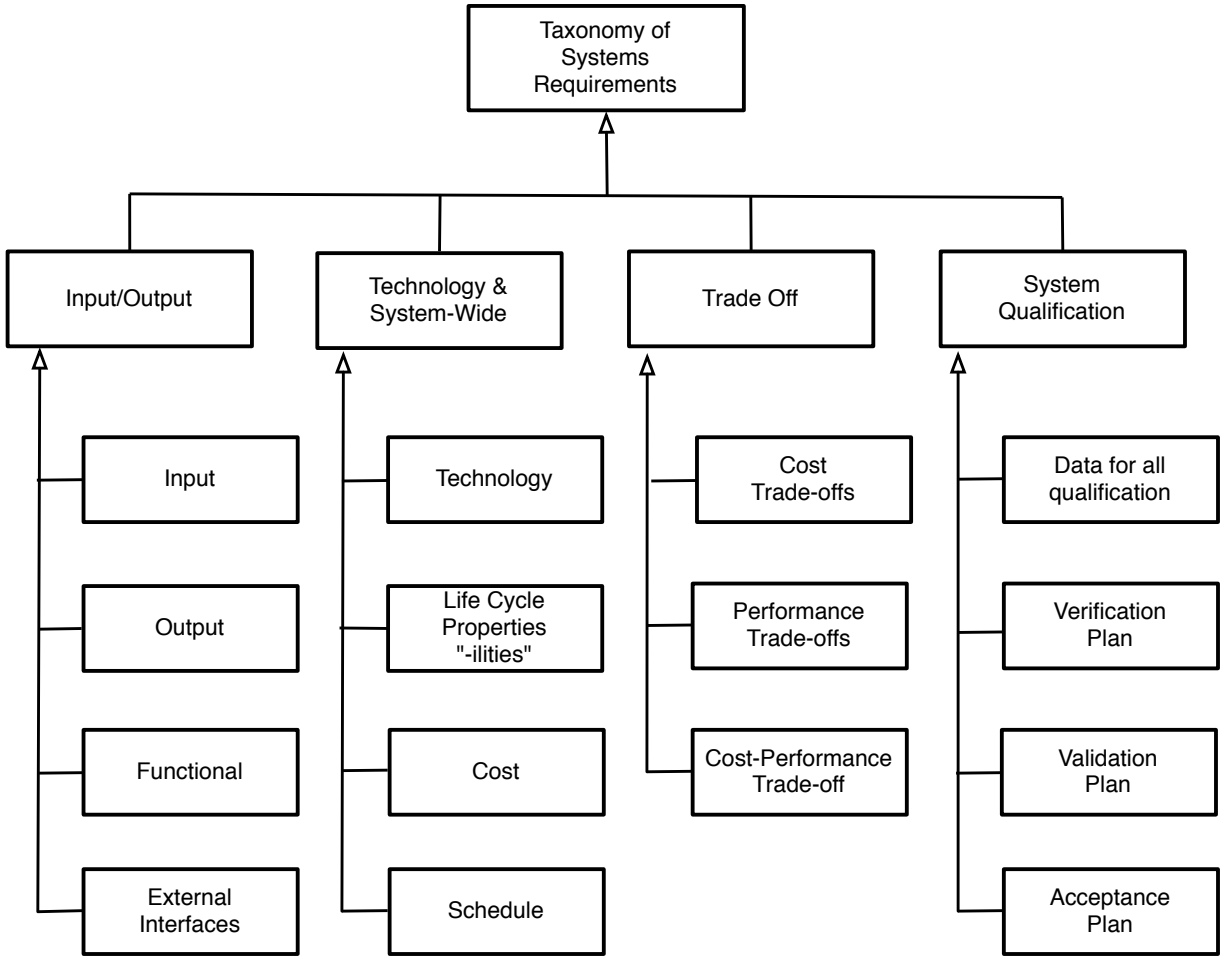
Scheduled Maintenance of a Motor: Track power quality of an operating motor and notify operator in the event of significant deviations.

The Regulatory Compliance Archetype Use Case

Determine Compliance with NH PUC's 900 Net-Metering Rules

In a multi-stakeholder process, it is important to organize requirements & use cases in unifying frameworks.

Managing the Complexity: Types of Technical Requirements



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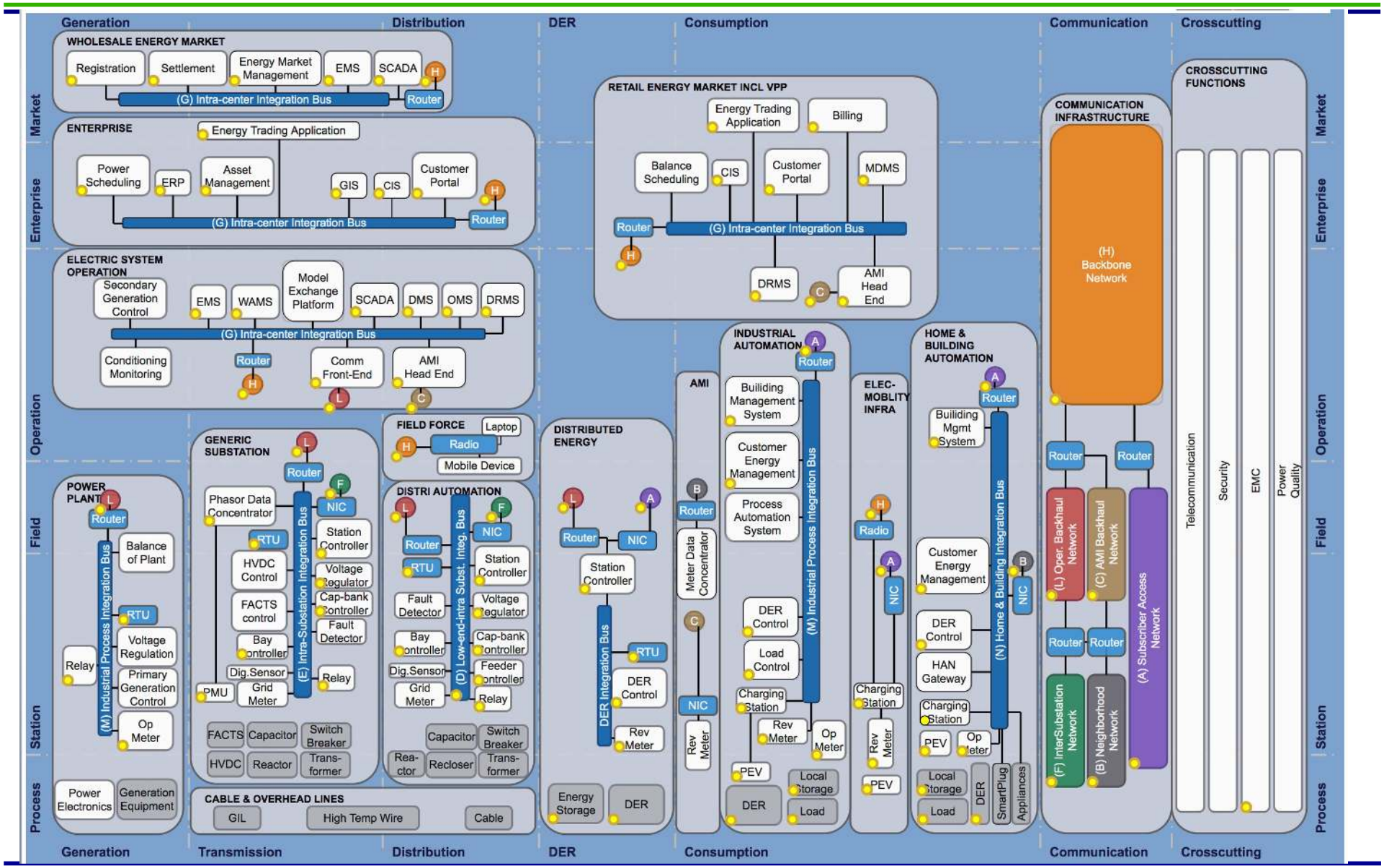
IEC Smart Grid Standards Map



THAYER SCHOOL OF ENGINEERING AT DARTMOUTH

LINES LABORATORY FOR INTELLIGENT INTEGRATED NETWORKS OF ENGINEERING SYSTEMS
EMPOWERING YOUR NETWORK

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7. ***Address Governance and Implementation Challenges*:**

Q: What do you think might be some important governance and implementation challenges?

One Answer: We got this! What could possibly go wrong?!?!

Your Answer: _____*Write your answer in the chat box*_____

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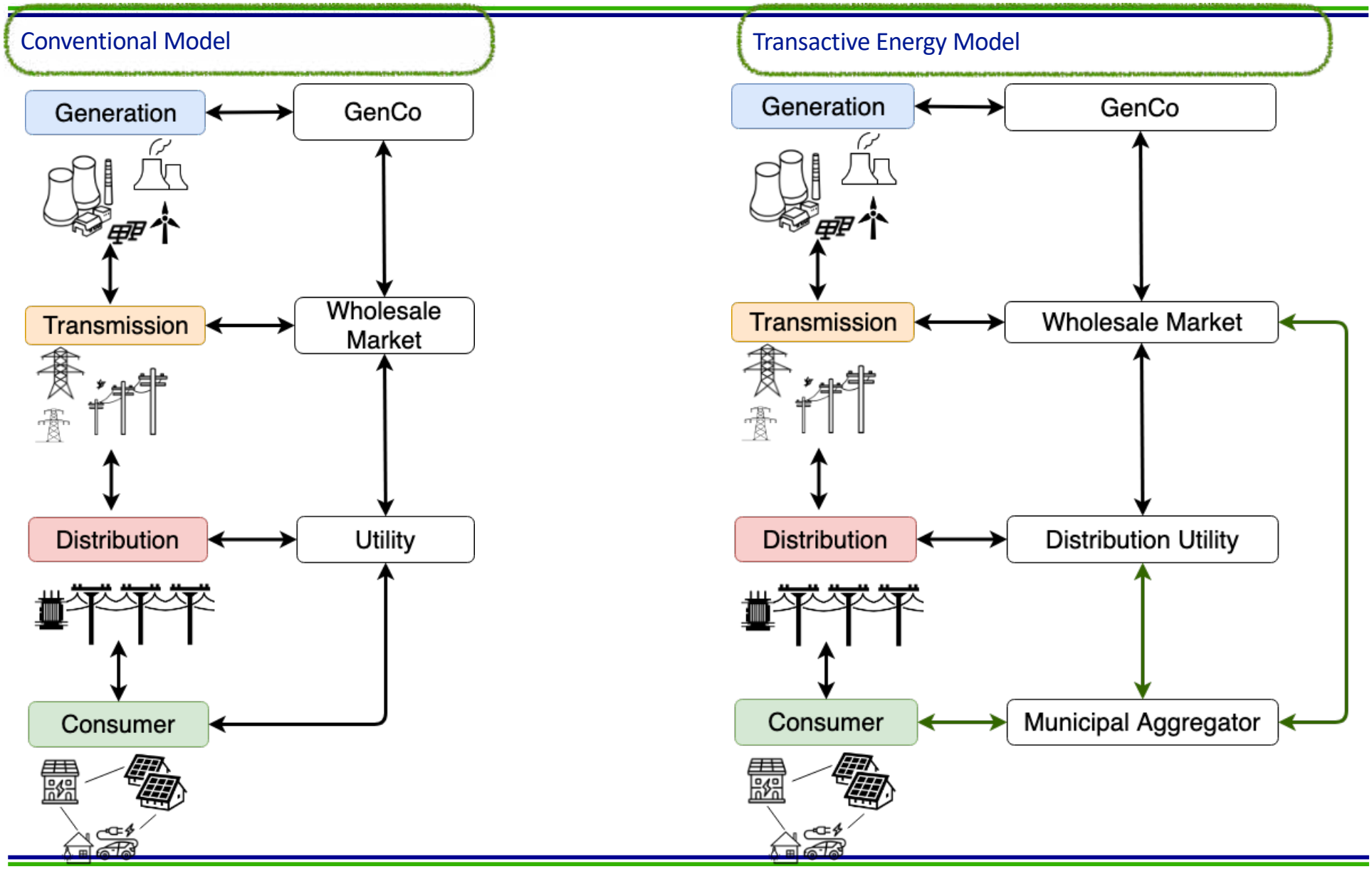
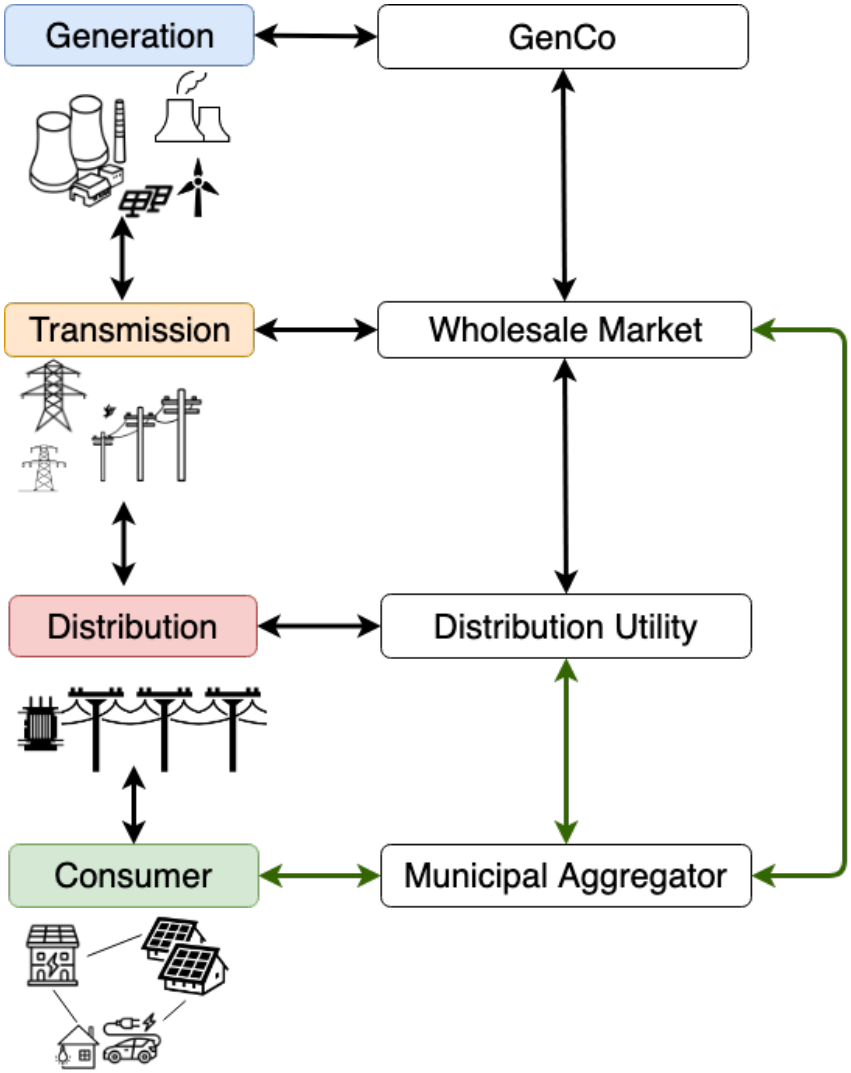
Conventional vs Transactive Energy Model



How is the Transactive Energy Model Different?



Municipal aggregation enables:

- Customer choice
- Access to cleaner cheaper electricity
- Access to real-time wholesale prices
- Peer to peer electricity trading

How do we achieve this?

- Collect relevant data
- Develop software to simulate the market

LEBTEC Software Development

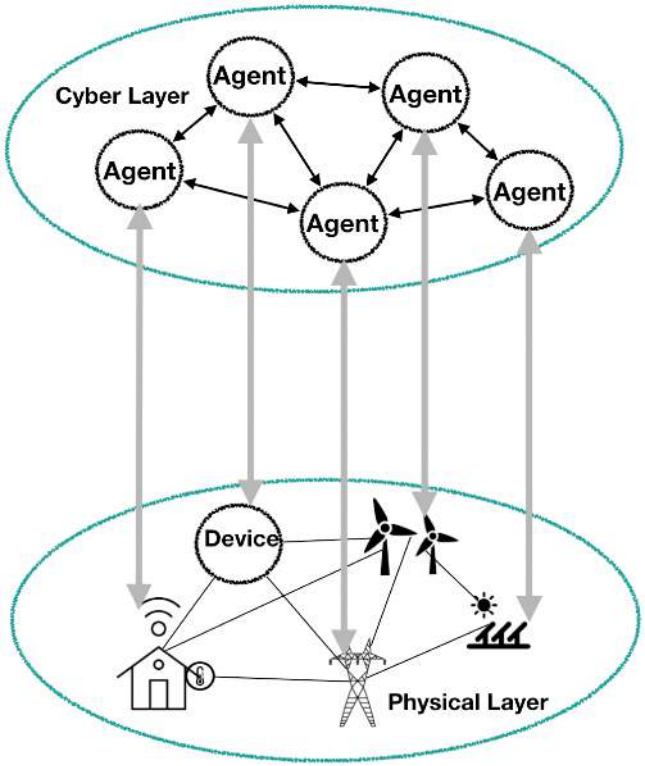
Industrial State of the Art Solutions

POWER LEDGER

LO3 ENERGY

Limitations: *No guarantees of convergence*

Academic State of the Art: ADMM



Limitations: *No guarantees of physical security*

Our Solution:

- Guarantees convergence
- Physical security
- Economic optimality

Bringing a decade of renewable energy integration experience to Lebanon!

LEBTEC Data Processing

Data:

- GIS Layer
- Power injections

Worked with:

- Liberty Utilities
- LEAC

Next Steps:

- Finalize data processing
- Combine the software model with data
- Run simulations

Biggest Challenge:

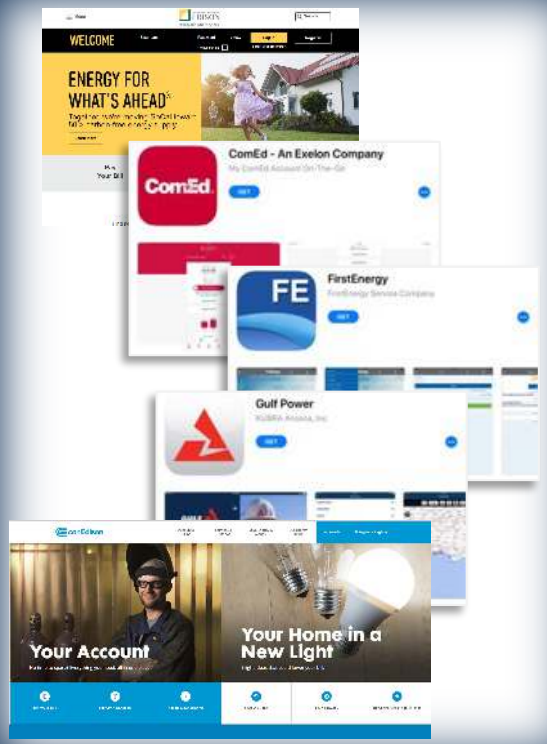
- Data collection and processing

Imagine…A World Where Customers Are Part of the Solution

The Shared Integrated Grid

Creating a Shared Integrated Grid (#sharedgrid)

Customer Engagement



Connected Devices = Shared Economy

Community Level Coordination

∴ **eIoT-XIM enables the eIoT which in turn enables a Shared Integrated Grid!**

Thank You

Conceptualizing the Development of an energy Internet of Things eXtensible Information Model:

A Dartmouth-LIINES & EPRI Collaboration

Amro M. Farid
Associate Professor of Engineering
Adj. Assoc. Prof. of Computer Science

Thayer School of Engineering at Dartmouth

LIINES
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EMPOWERING YOUR NETWORK

http://engineering.dartmouth.edu/liines

Invited Presentation:
Stanford University

Stanford, CA
July 15th, 2020

ENERGY & NATURAL RESOURCES

Refocusing on the Consumer

Utilities regulation needs to prepare for the "prosumer" revolution.

BY AHMAD FARUQUI

Back in 2017, a man attending a Florida workshop on utility rate design stumped me by asking if I had traveled all the way from San Francisco just to tell the audience how utilities should modernize their rate designs. He was obviously unimpressed with what I had said. I asked him, "What were you expecting?" He said he thought I would talk about rate design in which electricity consumers were also producers—"prosumers"—and there was no grid or utility. I was inclined to tell him to go ask the bartender about that, but that would have been impolite. So, I told him that I was not looking that far out in the future, but focusing on market developments over the next two decades

In the years since, I have seen more and more of my neighbors turn into prosumers. I recently became one myself, with solar panels and a battery storage system installed in my house. I also drive an electric vehicle (EV). The distant future has arrived much sooner than I expected, at least in my neighborhood. And, while California continues to dominate the nation in the sheer number of prosumers and EVs, it is not difficult to imagine a not-so-distant future in which much of the nation will begin turning into Prosumer Land.

THE CONSUMER REVOLUTION

A revolution is underway in the electric utility industry. The signs of this were evident long before the Great Recession of 2008–2009 slowed load growth. I spoke at Goldman Sachs' Annual Power Conference in New York City soon after the recession ended and made that point. But the facial expressions of the investment analysts in the room told me they were not buying it. I was invited to speak at the same event two years later. I gave

AHMAD FARUQUI is principal of the Brattle Group.

a similar message, saw a few people nodding their heads, but I've yet to be invited back there to speak again.

In 2014, I spoke at a conference on the outlook for electricity sales and peak demand. My message of flattening demand resonated with the technical audience. Two of the three other panelists agreed with me. (The fourth insisted an industrial renaissance was underway that would propel growth.) The only issue among those who agreed with me was which forces were driving this change. Some said the primary force was utility demand-side management programs. Some said it was governmental codes and standards. Some said it was the arrival of distributed energy resources. And some said that it was fuel switching away from electricity.

Today, as we stand at the cusp of the third decade of the 21st century, the trend is no longer being questioned, probably not even at Goldman Sachs. Over the past decade, consumers have decisively and irreversibly changed the way they *think* about electricity, how they *consume* electricity, and *when* they consume electricity. And some have turned into prosumers.

Of course, as we have discovered, no two customers are alike. Even within the same household, husband and wife often differ on how they want to live their lives. Children introduce more uncertainty into the energy decision-making. Of course, all customers want choice, but they only want what they want. Yet, utilities often offer just one product to all customers in a "rate class"—delivered electricity at a certain rate—thereby avoiding accusations of discrimination. A few offer some choices, but these are often marketed in a jargon that would politely be called obscure and they use communication channels that sometimes don't even reach the customer.

It's safe to say that diversity is the hallmark of customer preferences for consuming electricity, just as it is for any other product or service. Electricity is no exception. Utility consumers fall into several categories. Some want bill stability and are willing to pay more for it. Some want the lowest bill and are willing to shift and reduce load. And some have gone organic in every aspect of their lives and want to buy only green power to mitigate climate change. Yet, most utilities simply offer a single rate to all of them. Imagine what would happen to sales at retailers like Nordstrom's if they only sized their merchandise as "one size fits all."

ISTOCK / GETTY IMAGES PLUS

I recently called my local utility's customer service number and asked which rate I should pick given that rooftop solar panels and battery storage were about to be installed in my house. I was told to pick such-and-such a rate as a starting point. My bill would now run 10 pages, but I should ignore all the pages except 1 and 3. I asked if the recommended rate would be the best rate for me since I also have an EV. She said there was no easy answer to that question. It would be best if I waited for another year to figure out my best rate, which of course meant that I may end up paying more in the next 12 months.

THE TECHNOLOGY REVOLUTION

Concomitantly with the revolution in consumer tastes, an all-embracing technological revolution is underway,

spurred by the advent of digital technologies. Just about all customers have smart phones today. Currently, about half of all customers have smart meters. But smart price signals are only rarely being transmitted through those meters.

More and more customers have energy-efficient appliances with digital chips embedded in them. In fact, you can no longer buy energy-hogging appliances even if you want to. Some customers live in highly energy-efficient dwellings, some with solar panels on their roofs and even batteries for storage. In Hawaii, which has very high electric rates, some 60% of new solar installations in Honolulu are being paired with batteries. In California, where planned power shutdowns are being carried out to prevent wildfires, the same can be expected. This has temporarily pushed up storage battery prices, but they are on a long-term declining trend. Finally, more and more customers are buying or leasing EVs despite their high prices and short range, and despite their especially high prices in California and Hawaii.

DISINTERMEDIATION OF UTILITIES

Disintermediation of utilities involves the entry of third parties that sell products and services to utility customers that reduce utility sales and revenues. This trend is well underway and appears to be unstoppable. Utilities may think they are regulatorily protected monopolies, but customers keep divining creative ways to manage their energy use outside of utility (and commission) directives. This should not surprise anyone, but it does seem to have eluded more than one utility and one regulatory body.

Electricity consumers are going to act in their self-interest, just as they do in every other market. Their eyes glaze over when they are told they cannot do such-and-such because it would be an uneconomic bypass of the grid and create cross subsidies between customers.

Customers on the frontier of change want local control and grid independence. Consumer choice aggregation is taking off like never before in California and is being considered in several other states, such as Colorado and New Mexico. The drivers are many, ranging from consumer desires to consume green energy, have local control, and lower expenses. But the ultimate driver in most cases, as mentioned by a utility executive to me, is a deep-rooted anti-utility sentiment.

New entrants that are disintermediating utilities include global tech giants, start-ups with unwieldy names, and even home security firms and hardware stores. The electric customer is no longer the exclusive preserve of the regulated monopoly.

While talking to a senior officer of a large utility the other day, I mentioned the "prosumer" conversation I had in Florida a few years ago. I thought he would dismiss the scenario that the skeptic had laid out, much as I once did. Surprisingly, he said that he was finding himself more and more in that camp. He added that economic history tells us that no industry has remained a natural monopoly forever. Utilities must change their ways if they want to survive.

ARMAGEDDON?

At one time, the utilities conference circuit included talk of "death spirals"—utilities slowly collapsing financially as a result of market change. Today, the talk is of sudden "Armageddon." Whether the end is at hand or a chimera won't be known for another decade or two. Still, if utilities and regulators continue to do business as they have for the past century, they will accelerate the demise of the electric industry.

In a *Harvard Business Review* article entitled "Marketing Myopia," marketing professor Ted Levitt wrote ominously:

> Every major industry was once a growth industry. But some that are now riding a wave of growth enthusiasm are very much in the shadow of decline. Others that are thought of as seasoned growth industries have actually stopped growing. In every case, whenever growth is threatened, slowed or stopped is not because the market is saturated. It is because there has been a failure of management.

He specifically cited the example of railroads forgetting they were in the transportation business, not just the railroad business. He cautioned oil companies about the advent of electric vehicles and electric utilities about the advent of rooftop solar panels. What is noteworthy is that the article was written in *1960*. It is even more relevant 60 years later.

WAITING FOR GODOT

In the meantime, utilities and regulators are moving slowly—one might even say ponderously—through rate cases. Regulatory lag is breaking records, often running into years. The slowest-moving drama in history is being played out in hearing rooms from coast to coast, from ocean to ocean.

Consider these case studies from my career. I have observed these instances of delays and back-tracking first-hand:

1976 The Electric Power Research Institute (EPRI) initiated the Electric Utility Rate Design Study at the behest of the National Association of Regulatory Utility Commissioners on behalf of the industry. It was carried out over several years with the close involvement of commissions, utilities, academics, and consultants. Nearly a hundred reports were produced on various aspects of time-of-use (TOU) rates. The study got a major boost when Congress passed the Public Utility Regulatory Policies Act (PURPA) in 1978. The study came to two primary conclusions: First, it was cost-effective to deploy TOU rates—rates that fluctuate to reflect marginal prices during the electricity demand cycle. Second, TOU rates could be developed using either embedded costs, which was the tradition in the industry and the favorite of accounts, or marginal costs, which was the approach favored by economists. Luminaires such as Alfred Kahn, chair of the New York Public Service Commission, chaired the advisory committee in its first phase. I joined EPRI in 1979 and worked on the study for a year. The biggest barrier to the deployment of TOU rates

back then was the lack of smart meters. Today 50% of homes have smart meters, yet less than 5% of homes have TOU rates. The biggest barrier has turned out to be political.

1980s This decade saw some limited deployment of TOU rates in certain states, but those efforts were soon eclipsed by the emergence of demand-side management to enhance economic efficiency and lower customer bills. The main policy instrument was financing and rebates. Pricing was judged to be the ideal policy instrument, but such policies were deferred for later consideration, once again because politics intervened. TOU rates were relegated to the world of academe. A cottage industry arose comprised of academics who designed and evaluated TOU pricing experiments.

1990s The industry began to move toward restructuring, inspired by the liberalization of power markets in Great Britain during the Margaret Thatcher era. Conferences were held on the next generation of pricing designs, which would factor in retail customer choice and market restructuring. Plenty of books, papers, and articles were published. Once again, academics and researchers thrived. Not customers.

2000s I was tasked with finding ways to enhance energy efficiency in the Kingdom of Saudi Arabia. I discovered that a major barrier was that prices for electricity were heavily subsidized. I started asking people if I could meet the person who set prices, but no one could tell me who that was or where he worked. The utility said it was probably the regulator. The regulator said it was probably the ministry. When I spoke to the ministry, officials there were evasive. I persisted. Finally, someone told me the King set the prices. I decided not to pursue the topic. I figured out that His majesty did not want to trigger a revolt on the Arab street by raising electric rates. He had raised the price of petrol a few years earlier, but that had triggered an adverse reaction, forcing him to roll back the prices.

2002 Around the time of California's energy crisis, Puget Sound Energy, which serves the suburbs around Seattle, deployed very attenuated TOU rates (which it called "real-time pricing"). Customers saved hardly anything, and a revolt ensued when shadow bills were sent out showing that. The new CEO of the company, a long-time advocate of TOU pricing when he was at Pacific Gas & Electric, shut down the program. The utility could have improved the savings opportunities for customers by increasing the off-peak discounts but chose not to do so. The national movement toward TOU pricing was set back a decade. Regulators and utilities drew the wrong conclusion, that TOU pricing was to blame for the revolt, when the problem was with the specific design of the TOU rate and not with TOU pricing in general.

2002–2004 Soon after the worst energy crisis in its history roiled California's power markets, several economists (including me) signed a manifesto that concluded in part that the best way to avoid another crisis was to reconnect the retail and wholesale markets that had become disjointed when the industry was restructured in 1998. In 2002, the California Public Utilities Commission initiated a proceeding on advanced metering, demand response, and dynamic pricing. An experiment, called the Statewide Pricing Pilot, was carried out jointly by the three investor-owned utilities in California to test the merits of dynamic pricing. It ran during 2003–2004 and was monitored through regular meetings of a stakeholder group. It showed conclusively that customers responded to dynamic pricing signals by reducing peak loads and shifting peak usage to off-peak usage. Within a few years, all three investor-owned utilities were given approval to move ahead with advanced meters. Their business cases included an ample dose of dynamic pricing. Two decades have passed, millions of dollars have been spent on a new crop of pilot programs to confirm (yet again) that Californians respond to changes in the price of electricity. So, almost two decades after the energy crisis, the state will witness the ultimate anti-climax: Very mildly differentiated TOU rates will be rolled out to all customers. No one will save much, even if they move all their load to off-peak hours. People will either ignore the rates or get annoyed. I see Puget Sound Energy, Part II, in the making.

2006 I was invited to speak on smart meters and smart rates by the National Association of Regulatory Utility Commissioners. In the years that followed, I was invited back nine times to speak on the same topic. After one of those sessions, a commissioner from New Jersey said she was impressed with the benefits of smart meters and wanted to know if there was some way to get those benefits without the meters. I wanted to tell her I wish there was a way to get the benefits of sunlight without the sun. But I bit my tongue and just smiled.

2007 The chair of the California Energy Commission noticed that only half of the goals the state had laid out for introducing price responsive demand in its Energy Action Plan had been achieved. She hired me to work with stakeholders to identify ways to enhance that percentage and reach the goal of having 5% of California's peak demand be price responsive. My report recommended that the commission use its load management standards authority to require that all new homes be equipped with smart, communicating thermostats. This would allow critical peak pricing signals to be transmitted to central air conditioners, a major driver of peak loads, thereby balancing demand and supply in real time. Unfortunately, nothing came of the proposal after a conservative talk show host stirred up an Orwellian vision of the program for his radio audience.

2009 After speaking at a conference on demand response, I talked on the sidelines with the CEO of PJM, the grid system that serves much of the mid-Atlantic. I asked him if he liked

the discussion of price responsive demand. He said he did not trust price response because it wasn't tangible; it was not steel in the ground. His job depended on keeping the lights on. If the lights went out because the price response did not materialize, he would be out of a job. I responded that he couldn't control the weather or the economy; he should be used to planning under uncertainty. Price response is not any more volatile than the economy or the weather, I noted, and he should be able to count on it. Besides, it would save consumers money. By the time I finished my point, he had turned away and was speaking with someone else.

2009 I carried out a study for the New York independent system operator on the benefits of real-time pricing. The quantified benefits were significant. But little subsequently happened because the issue fell under the dominion of the state commission, and it was reluctant to move on rate modernization because the state lacked smart meters. Of course, that was just a convenient excuse.

~2009 Inaction is not just a North American problem. About 10 years ago, in Saudi Arabia, I was presenting the final results of a project designed to promote energy efficiency in the country to the executive suite of the government-owned electric utility. Halfway into my remarks, a vice president asked me why I kept using the word "customer" over and over. His tone was testy. I was not sure what to make of his question because all the work I had done was designed to encourage customers to invest in higher-efficiency equipment. It could not have been a language problem because he spoke fluent English. I answered, "Because the customer is the king." The audience's faces blanched and I realized the gravity of what I had said. Mercifully, one audience member rescued me by saying that customers were writing letters to the editor complaining about the poor customer service of the utility.

2009 The Federal Energy Regulatory Commission conducted a state-by-state assessment of demand response potential and identified the best way to harness it was to deploy smart meters and offer smart rates to all customer classes. Several workshops were held with stakeholders and a national action plan was launched. But the idea failed on the launch pad because the implementation plan that followed was devoid of actionable policies, directives, and incentives. I wrote to the chair of FERC and said the plan was a damp squib. He asked if I knew the meaning of that British expression. What more was there to say?

2000–2010 Having observed the California energy crisis from afar, Ontario, Canada decided to roll out smart meters and deploy TOU rates as the default tariff in the mid-2000s. However, the price differential between the peak and off-peak periods was highly attenuated. Also, the TOU differential only applied to the generation portion of the tariff. Nonetheless, a three-year analysis carried out by a team of researchers (including me) showed that customers were reducing peak load by a few percentage points, but the savings were atrophying year after year. A recommendation that we had made in 2010 to accentuate the savings opportunities through dynamic pricing was ignored.

Late 2000s The Harvard Electricity Policy Group provides a good forum for discussing smart meters and smart rates. During one of my presentations at the event, a commissioner from Washington, DC asked me if customers would response to price changes, since electricity was a necessity. She asked me this question after I had shown an overwhelming amount of the evidence that customers do respond to price.

2010 At a major law school conference on the future of the utilities industry, I talked to the chair of the utilities commission about the delays in policymaking. He said that the utilities were frozen in time. Later, I made the same comment to a senior executive of the local utility. She said that the regulators were frozen in time.

2010s I have spoken a few times in Hawaii on smart grid and smart rates during the past decade. One of the state commissioners promised to write "a postcard to the future" to the mainland on how the state was going to become 100% renewable before 2050. Yet, to this day, the state has no smart meters, let alone smart rates. In the meantime, a third of single-family homes in Oahu have installed solar panels on their roofs. Some 60% of new solar customers are also installing batteries. I have seen several EVs on the road and Tesla has an incredible showroom right in the heart of Waikiki. Consumer have once again left the utility and the commission behind.

2011 After sharing the results of a dynamic pricing experiment with a senior utility executive, I recommended what I thought was the most forward-looking rate design from those that had been tested in the experiment. He picked an anodyne rate design. My face must have given away my inner thoughts because he added quickly: "I am not stopping you from writing your articles and giving your talks. But this is my company and I will do what I think is in the best interest of the company."

2012 A workshop sponsored by the California Foundation on the Environment and the Economy reexamined the tenets of California's inclining block rates. Three speakers—two professors from Berkeley and I—spoke at the event. This was followed by comments from several stakeholders. Following up on the workshop conclusions, the California Public Utilities Commission initiated proceedings to redesign the inclining block rates. Five steeply differentiated tiers had been created after the energy crisis. All the inflation that came in the years that followed

was lumped onto the upper three tiers. After deliberating on the issue, the commission unanimously passed a rule to flatten the tiers. The five tiers would be replaced with just two. But at the last minute, to arrive at a unanimous decision, a super-user surcharge was introduced for large users. Currently, it stands at 55¢ cents per kilowatt hour for San Diego Gas & Electric and just under 50¢ for Pacific Gas & Electric. Simultaneously, the state wants to decarbonize completely by 2045 and it views electrification of buildings and transport as the best way to get there. But how do you convince consumers to switch to heat pumps when electricity is prohibitively expensive compared to natural gas? I have raised this issue with some of the energy division staff who are working on decarbonization. They said it's an issue for the rate design group and they will get to it in the future. Once again, the can has been kicked down the road.

2012 I was retained by the Australia Energy Market Commission to examine the case for applying dynamic pricing for distribution tariffs. In Australia (as in Texas), customers have to choose a retail energy supplier. There is no default regulated supply option; the regulator only sets distribution tariffs. My final report recommended reforming this, but I was told there were political challenges to be overcome. We discussed a variety of different deployment mechanisms and ultimately devised a scheme that would make these rates mandatory for the largest customers, optional for vulnerable customers, and the default tariff for everyone else. I thought the recommendation was touched by Solomon's wisdom. Alas, the government did not agree. To this day the recommendation has not been carried out.

2014 Minnesota initiated a process for creating the grid of the future. Demand response is a major priority of the state and studies indicate the best way to harness its potential is to deploy dynamic pricing to all mass-market customers. The state first began considering the deployment of smart meters and smart pricing in 2001, following the example of Puget Sound Energy. But the California electricity crisis prompted Minnesota to pull back. A pilot with various time-varying rates was scuttled. Finally, after years of deliberation, a simple TOU regime will be launched.

2015 I was invited by the New York Law School to be a keynote speaker at a conference on time-varying rates. The state energy czar opened the event, followed by the chair of the utilities commission. I gave my talk and hoped it would make a difference. To this day, the state is still trying to make up its mind about smart meters and doing pilots with innovative rate designs. New York's energy vision is taking shape very, very slowly.

2019 While discussing rate reform in Texas, a former utility commissioner told me to wait another five years because the legislature had recently had a lot of turnover and the new lawmakers needed time to get up to speed. I said I have been hearing that for the past four decades.

2019 In a northwestern state, after I had testified for five hours spread over two days, a staff member walked me to my car and said, "Thanks for coming, but I think I the commission will just kick the can down the road."

2019 In a Canadian province, I shared several ideas for moving customers to innovative rates to help utilities stay in step with their customers. I noted that there were EVs on the road there, just about everyone carried a smart phone, and consumers there were buying energy-efficient appliances. That's why it was time to modernize rates. I was told the status quo remained an option for electric rates.

It's obvious that both regulators and energy executives are frozen in time and they know it. They spend much of their time blaming each other for the delays. The blame game continues unabated at many industry events. The pace, ambiguity, and inconclusiveness of this regulatory drama seem to be a reenactment of the play *Waiting for Godot*.

THE MISSING CUSTOMER

For all practical purposes, utilities think of the regulator as their main customer. The end-use customer is almost an afterthought, consigned to being a "ratepayer" or "meter." Whatever innovations take place on customers' premises are referred to as "behind the meter." Imagine how Nordstrom's would thrive if it refused to consider what happens "behind the cash register."

The regulators, in turn, often think of the legislature or the governor as being their main customer. The elected officials have their eyes on the next election. Their final customer, the American voter, is actually the utility's customer and that's how the circle is completed.

As we all know, emotion trumps logic when it comes to winning votes and often leads to unsustainable energy policies and unrealistic timetables. Elected officials change every few years and regulators often change every few years. Depending on the frequency of the crises that routinely afflict utilities during these tempestuous times, utility CEOs also often change every few years. That's chaos theory in action.

It used to be said that rate design is more art than science. In fact, just last year, that notion was put to me in a regulatory hearing where we were discussing the case for demand charges. I said the notion was mostly rooted in politics. The whole room broke out in laughter.

Earlier, I had been grilled for 90 minutes by one of the commissioners. After the cross-examination ended, a person came up to me and said that I should write a book about these encounters. I said I have certainly had my share, trying to push regulators and

utilities to listen to their customers.

A couple of years ago, I asked a newly appointed regulator in a large western state how independent of state government the commission's policies would be. She said that she and her colleagues respected their chief executive very much. I said that was not my question. She asked me to be more specific. Because that state has more solar panels than any other state, I asked her when we should expect to see a change in net energy metering policies. Her answer left me stunned: "You know that the solar lobby in the state is very powerful."

TIME FOR CHANGE

As a freshman at the University of Karachi in 1969, I came across Paul Samuelson's *Economics* textbook. Every chapter began with a quote. One that has stayed with me is from Lewis Carroll:

> The time has come, the Walrus said
> To talk of many things:
> Of shoes—and ships—and sealing wax
> Of cabbages—and kings;
> And why the sea is boiling hot;
> And whether pigs have wings.

While every state is in a big rush to move ahead with decarbonization and has specified some very aggressive timelines for becoming 100% decarbonized, just about all the policy solutions are on the supply side. There is almost no inclusion of dynamic load flexibility, which could help deal with the intermittent nature of renewable energy.

For those of us who work in the electric utility industry, the time has come to rethink regulation, reimagine the utility, and reconnect with the real customer. That journey can no longer be delayed.

The best way I can think of beginning this journey is to make "customer-centricity" the guiding principle. This means leaving the past behind and focusing on the future. It does not mean simply creating a new website or sending frequent text messages to customers. Nor does it mean just engaging in social norming to shape customer behavior. It means changing the culture of the industry, reimagining utilities as service providers, hiring staff with an open mindset and new skills, reaching out to customers to understand their changing needs, and developing new products and services to meet those needs.

This journey will involve finding new ways to engage with customers and observing those customers in real time to understand their energy-buying decisions. Unless these steps are undertaken, the customer is going to leave both the utility and the regulator in the dust. *R*

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An enterprise control assessment case study of the energy–water nexus for the ISO New England system

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ABSTRACT

The generation mix of Independent System Operator in New England (ISO-NE) is fundamentally changing. Nuclear, coal, and oil generation facilities are retiring and are replaced with natural gas, solar, and wind generation. Variable renewable energy resources (VREs) such as solar and wind present multiple operational challenges that require new and innovative ways to manage and control the grid. This paper studies how water supply systems (water and wastewater treatment), and water-dependent electricity generating resources (hydro, and thermal power plants) can be operated flexibly to enhance the reliability of the grid. The study's methodology employs the novel Electric Power Enterprise Control System (EPECS) simulator to study power systems operation, and the System-Level Generic Model (SGEM) to study water consumption and withdrawals. This work considers six potential 2040 scenarios for the ISO-NE energy–water nexus (EWN). It presents a holistic analysis that quantifies grid imbalances, normal operating reserves, energy market production costs, and water withdrawals and consumption. For scenarios with high amounts of VREs, the study shows great potential of water resources to enhance grid flexibility through improvements in load-following (up to 12.66%), and ramping (up to 18.35%) reserves. Flexible operation also results in up to 10.90% reduction in the total time VREs are curtailed. Additionally, flexible operation reduces water withdrawals by up to 25.58%, water consumption by up to 5.30%, and carbon dioxide emissions by up to 3.46%. In general, this work provides significant insights into how to jointly control the water and energy supply systems to aid in their synergistic integration.

1. Introduction

The bulk electric power system of New England is fundamentally changing to include more solar and wind generation resources. This evolving resource mix has triggered changes to how the electricity grid is managed and controlled. The bulk of these changes have been in capacity and transmission expansion. However, with the growing uncertainty and variability introduced by variable renewable energy, there is an even greater need for increased amounts of operational flexibility [1,2]. ISO-NE is the independent system operator for the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. It is tasked with performing three critical roles namely; (1) coordinating and running the electricity grid for the region, (2) designing, managing and running the region's deregulated wholesale electricity market based on minimum generation costs, and (3) planning the system such that it continues to meet the region's electricity needs over the next 10 years. Water plays a fundamental role in the ISO New England (ISO-NE) system. Conventional and run-of-river hydro make up over 9% of the overall electricity generated in the six New England states [3]. An additional 1% of electricity generation comes from the two main pumped energy storage facilities, Bearswamp and Northfield [3]. In the meantime, over 83% of the current ISO-NE electricity generation fleet comes from thermal generation facilities which withdraw and consume large quantities of water for cooling purposes [3]. In spite of the changing resource mix, recent studies predict that thermal generation facilities will still account for a significant percentage of future generation facilities in 2040 [4,5]. Fig. 1 illustrates the extent of the coupling between the water and electricity generation resources in New England. From Fig. 1, it is clear that most generating facilities are located near a water source and rely on adequate water supply to perform their function. These factors not only indicate significant coupling between the water and electricity supply systems but they also emphasize the need for more coordination

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Nomenclature

Acronyms

EIA	Energy Information Agency
EPECS	Electric Power Enterprise Control System
EWN	Energy–water nexus
FCA	Forward Capacity Auctions
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
NGCC	Natural gas combined-cycle
NICR	net Installed Capacity Requirement
NREL	National Renewable Energy Laboratory
PHEV	plug-in hybrid electric vehicles
ReEDS	Regional Energy Deployment System
RPS	Renewable Portfolio Standards
RTUC	Real-Time unit commitment
SCADA	Supervisory control and data acquisition
SCED	Security-constrained economic dispatch
SCUC	Security-constrained unit commitment
SGEM	System-Level Generic Model
SOARES	System Operational Analysis and Renewable Energy Integration Study
UCED	Unit-commitment-economic-dispatch
VREs	Variable Renewable Energy Resources
CEII	Critical Energy/Electric Infrastructure Information

between the two systems. Specifically, the potential synergies between the two systems cannot be ignored especially as the electricity grid undergoes its sustainable energy transition.

Concern about water security is growing especially with climate change affecting hydrology patterns and the decline of freshwater resources [6–8]. At the same time, significant attention has gone into the integration of variable renewable energy into the electricity grid as a means of decarbonizing the electricity supply system. As discussed in the prequel to this paper [9], the challenges of renewable energy integration and energy–water-nexus are very much related. In addition to presenting low CO_2 emissions, VREs have very low life-cycle water intensities [10] hence reducing the overall water intensity of electricity generating systems. On the other hand, water is easily stored and therefore, has the potential to serve as a flexible energy–water resource on both the supply-side as well as the demand-side so as to support the integration of VREs into electricity operations [11].

The growing penetration of solar and wind poses several challenges to maintaining the reliability of the electricity grid. In addition to being highly variable, these resources also lower the overall marginal costs of electricity forcing thermal units into early retirement [2]. In the absence of established market rules for VREs participation, curtailment is widely applied as a way to balance power systems with high penetrations of VREs. While curtailment serves to balance the grid, it raises the overall production costs as well as emissions. Given these challenges, independent system operators and utilities are largely constrained with respect to maintaining the reliable performance of the grid [2]. Therefore, alternative techniques for managing VREs such as allowing these resources to provide active power support and operating reserves could greatly improve the operating flexibility of the grid [2,12]. Furthermore, engaging active demand-side participation in the provision of ancillary services such as reserves, and active power support through load-shedding or load-shifting would go a long way to improve the flexible performance of the electricity grid [12]. Water and wastewater treatment systems are already equipped with the necessary monitoring technologies such as supervisory control and data acquisition (SCADA) systems to provide ancillary services, and in turn improve their profits and also achieve a more robust operation of their systems. In order to better leverage the potential synergies in real-time operation of water and power supply systems, the methodologies of energy–water-nexus and renewable energy integration studies must converge.

1.1. Literature review

Despite the benefits of joint operation, renewable energy integration and EWN studies have not yet converged to realize benefits. While some EWN studies have quantified the withdrawals by thermal power plants, these studies have largely been conducted in isolation of actual operation of the electricity generation industry [13–15]. Thus, the full impact on either infrastructure is not assessed. For example, [16] quantifies water withdrawal and consumption coefficients primarily based on literature sources. Other EWN works have focused solely on optimizing the operations of water systems such as in the optimal operation and scheduling of water pumps to minimize electricity usage [17,18] and water pumping costs [19]. These include the optimal scheduling of water systems [20,21] and flexible operation of water systems for electricity demand response [22,23] and other ancillary services so as to maximize returns for water systems [24]. Finally, a small subset of EWN studies have presented mostly single-layer approaches that co-optimize the water and electricity networks. Examples of such works include the optimal network flow in [25], the economic dispatch in [26,27], and the unit commitment problem in [28] for a combined water, power, and co-production facilities. A majority of EWN studies however, still focus on specific case study geographies such as the Middle East [29,30], California [31], or North Africa [32]. Despite the large body of work and research on the energy–water nexus, there is still a lack of a generic, case and geography-independent methodologies that encompass all flows within, and between the water and energy systems [33,34]. In fact, a recent review [35] of EWN studies shows that these studies require integral methodologies that capture the overall complexity of the nexus.

In the meantime, renewable energy integration studies have often been case and geography specific and have mostly utilized unit-commitment-economic-dispatch (UCED) models of power system control to study the operation of electricity markets with large penetrations of VREs [36–38]. A significant percentage of these studies have taken statistical approaches to determine the impact of wind and solar forecast errors on dispatch decisions. A subset of renewable energy integration studies have recognized the vital role of reserves in the balancing performance of systems with high VRE penetration and have thus, focused on the acquisition of normal operating reserves such as load-following, regulation, and ramping reserves [39–42].

However, a recent review of renewable energy integration studies shows major methodological limitations [43]. Firstly, while some studies focus on reserve acquisition, the required quantity of reserves is usually based on the experiences of grid operators which no longer applies to systems with high penetrations of VREs [44,45]. Secondly, most studies only consider either the net load variability or the forecast error in determining the amount of reserves despite evidence that shows that both of these variables contribute towards normal operating reserve requirements [44,46]. Lastly, although studies have shown that VREs possess dynamics that span multiple timescales of power system operation [47,48], most renewable energy integration studies have largely neglected the effect of timescales on the various types of operating reserve quantities [43]. Farid et al. [43] proposed a holistic approach based on enterprise control to study the full impact of VREs on power system balancing performance and reserve requirements while considering the multi-timescale dynamics of VREs. *Enterprise control* is an integrated and holistic approach that allows operators to study and improve the technical performance of the grid while realizing

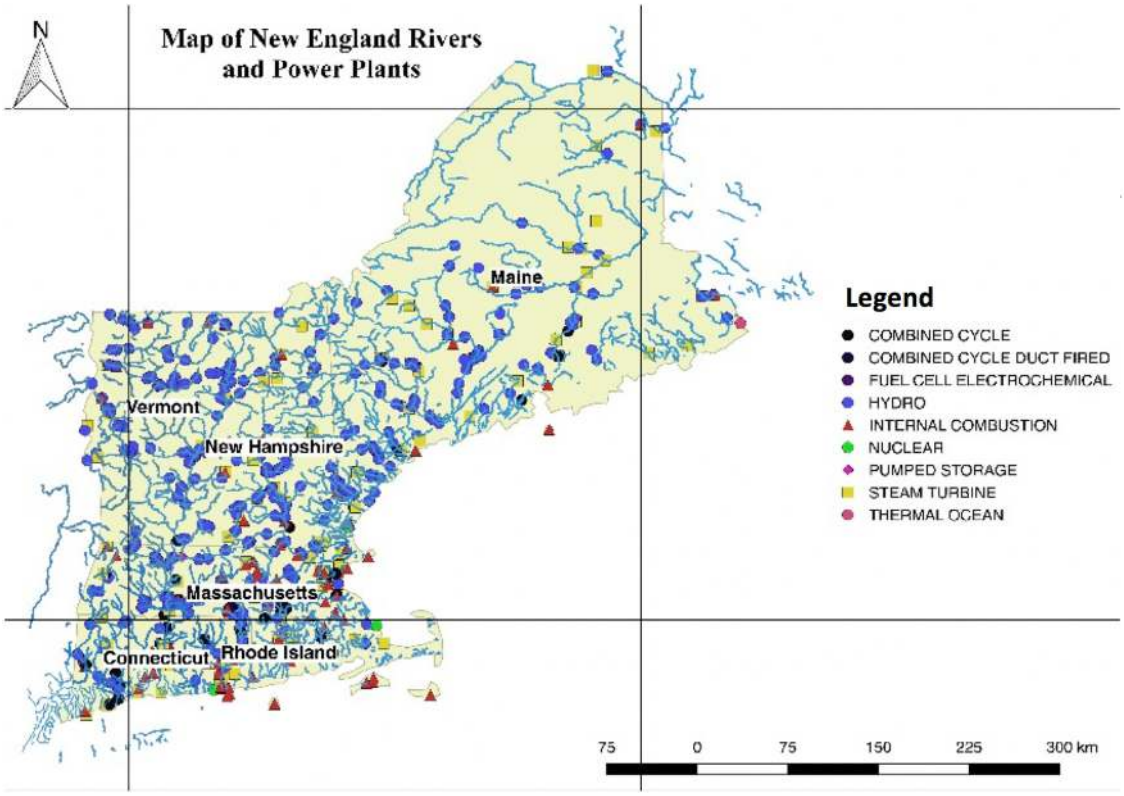

Fig. 1. A map of New England's electric power generation units and rivers.

cost savings [43]. An application of enterprise control in the form of the Electric Power Enterprise Control System (EPECS) simulator has been proposed in literature [43,49–52] and tested on various case studies including the ISO New England system [53]. In [53], the EPECS simulator is used to study the performance of the ISO-NE system on 12 scenarios with varying penetrations of VREs. This study highlighted the key role of curtailment and normal operating reserves on the balancing performance of the ISO-NE system. This paper extends the work in [53] and [9] to quantify the flexibility afforded the ISO-NE system through flexible operation of energy–water resources. For the purposes of this study, the term "energy–water resources" collectively refers to water and wastewater treatment systems (which are assumed to only consume electricity in this study), run-of-river and conventional hydro (which generate electricity), thermal power plants (which consume water for cooling and generate electricity), and finally, pumped energy storage (which consumes and generates electricity).

1.2. Original contribution

The main contribution of this paper is a case study of the energy–water nexus in the New England region. It utilizes the methodology presented in the prequel [9] and extends the results of renewable energy integration study found in [53] to specifically include several environmental performance and economic performance measures. This techno-economic study of the EWN in New England addresses twelve predefined 2040 scenarios; 6 with a "flexible" operation of energy–water resources and 6 "conventional" (i.e. inflexible) operation of energy–water resources. This case study takes the yellow rectangle of Fig. 2 as its system boundary and consequently is able to quantify the mass and energy flows in and out of the defined yellow system boundary regardless of the test case or geographical region. Additionally, this paper provides insight into some of the operational challenges presented by high penetrations of VREs and assesses the flexibility value of flexible energy–water resources by quantifying the amounts of normal operating reserves for the ISO-NE system for each scenario. Given that the methodology presented in the prequel [9] is generic and modular, the EPECS simulator is modified to reflect the ISO-NE operations as fully outlined in [53]. Each simulation scenario runs for a full year with one minute time step. In this study, the following operational parameters are quantified: (1) load-following, ramping, and regulation reserves, (2) the ability of water and wastewater treatment facilities to shift their electricity demand in response to changes in electricity supply, (3) the fuel flows of thermal units and their carbon emissions, (4) water withdrawals and consumption by thermal power plants, and (5) the overall effect of flexible operation of energy–water resources on the production cost of operation for the New England electricity grid.

1.3. Outline

The rest of the paper is structured as follows: Section 2 presents the methodology for the ISO New England EWN study. Section 3 gives a detailed description of the case study data. Section 4 presents the results of the study within the context of the key performance characteristics of the power grid. Finally, the paper is concluded in Section 5.

2. Methodology

As shown in Fig. 3, the methodology of the ISO New England EWN study is best viewed in two parts: planning and operations. Section 2.1 describes how the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) was used to evolve the 2030 ISO New England electric power generation capacity mixes to six distinct 2040 capacity mix scenarios. From there, the remainder of the section describes the Electric Power Enterprise Control System (EPECS) simulator as customized for ISO New England's operation [9,53]. Typically, it includes simulation functionality for two energy market layers: the Security Constrained Unit Commitment (SCUC) and the Security

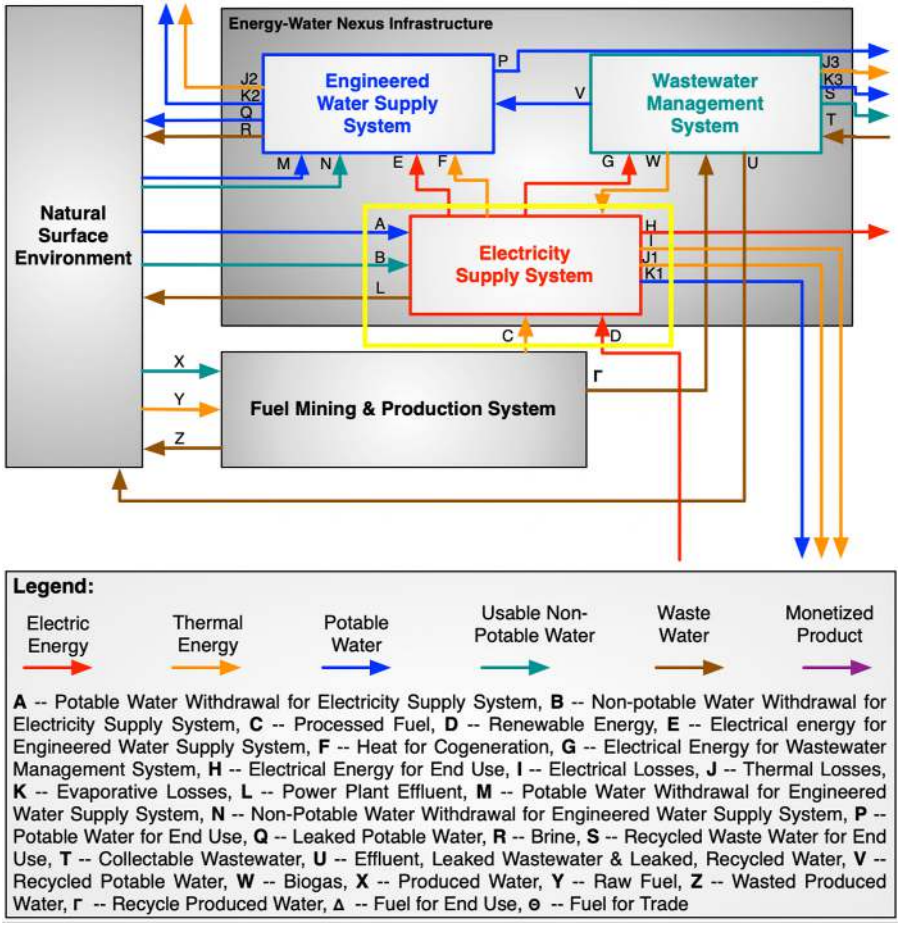

Fig. 2. A diagram of the physical flows between the physical infrastructures (water supply system, wastewater management system, and electricity supply system) and the natural surface environment that were quantified in this study [54].

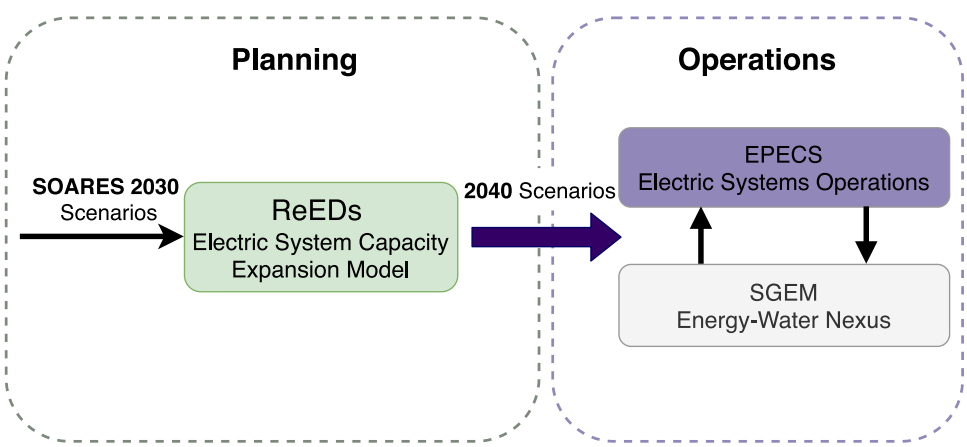

Fig. 3. Diagram of the Simulators Used for the ISO New England EWN Study.

Constrained Economic Dispatch (SCED), power system regulation and a physical model of the power grid itself (i.e. power flow analysis). For this study, the simulator has been customized for ISO-NE operations to include the Real-Time Unit Commitment (RTUC) as shown in Fig. 4. Furthermore, the SGEM model [9,55] is used to capture the essential physics of cooling processes for thermal power plants and in turn compute the water withdrawals and consumption for each power plant.

2.1. Regional energy deployment system (ReEDS) for capacity planning

ReEDS is a capacity planning tool that was developed by NREL starting in 2003. ReEDS is a tool that identifies the long-term evolution of the electric power grid for various regions in the United States [56–58]. At its core ReEDS is an optimization tool that identifies the cost-optimal mix of generation technologies subject to reliability, generation resource, and regulatory constraints [56–58]. The optimization has a

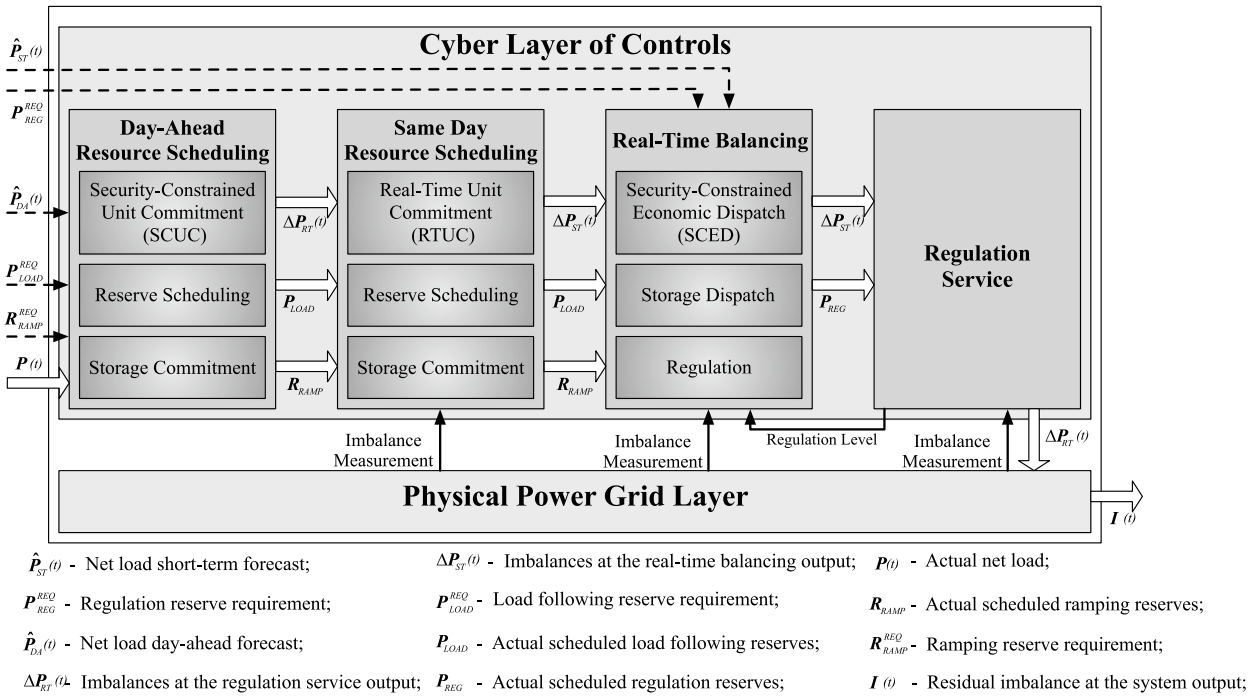

Fig. 4. Architecture of the Electric Power Enterprise Control System (EPECS) simulator customized for ISO New England operations [53].

two-year time step for a total of 42 years ending in 2050[56–58]. The final output of the simulation is generation capacity by technology, storage capacity, electricity costs among others [56–58]. This optimization tool was used to determine the evolution of the ISO-NE system from the 2030 scenarios to the 2040 scenarios. The model input assumptions were selected from configurations defined by the 2018 Standard Scenarios [59] (see Table 1) to align with the 2030 capacity mixes described in Section 3.1. Details on added capacities for each scenario can be found in Section 3.

2.2. The physical power grid

The physical power grid layer of Fig. 4 is represented by the zonal network shown in Fig. 5. The system data is in turn consolidated into the zonal network model of Fig. 5. This zonal network captures the power flows between pre-defined electricity load zones (i.e. "bubbles") along abstracted "pipes"; thus eliminating the need for Critical Energy/Electric Infrastructure Information (CEII) clearance. The EPECS simulator implements a lossless DC Power Flow Analysis to determine these flows as described in [9,53]. The high-level interface flow limits between the various bubbles are indicative of the line congestion often experienced in the ISO New England territory.

2.3. The security constrained unit commitment (SCUC)

The power system balancing operation commences with the day-ahead resource scheduling Fig. 4 in form of the SCUC. It is performed the day before to determine the best set of generators that can meet the hourly demand at a minimum cost. The time step for the SCUC is 1-hour and it determines the optimal set of generators for the next 24-hours. A simplified version of this program is presented in [9] and the full version customized for ISO-NE operations is presented in [53]. Note that the SCUC formulation used for this study extends the methodology in [53] to also include ramping constraints for wind, solar, and hydro resources [9]. Ramping constraints define the limits to how fast an energy resource can increase or decrease its output per unit time. When variable resources such as solar and wind become semi-dispatchable through curtailment, it means that these resources must ramp between two consecutive curtailment values (in time). This study assumes these variable energy resources can ramp between their maximum and minimum capacities within a single SCED time step of five minutes as defined in Ref. [9]. Conventional generation resources have ramp rates as well.

2.4. Real-Time Unit Commitment (RTUC)

The same day resource scheduling of Fig. 4 is conducted every hour through the RTUC. It uses an optimization program that is quite similar to that of SCUC but only commits and de-commits *fast-start* units. Fast-start units are defined by their ability to go online and produce at full capacity within 15–30 min. The RTUC runs every hour with a 15-minute time step and a 4-hour look-ahead. The complete mathematics for the RTUC can be found in [53] with slight modifications to include ramping constraints for wind, solar, and hydro resources as presented in [9].

2.5. The Security Constrained Economic Dispatch (SCED)

The real-time balancing operation of Fig. 4 is implemented through the SCED which is run every 10-minutes. The role of the SCED is to move available generator outputs to new set points in a cost-effective way. The SCED does not bring online any units but rather ramps up or down the available online units. The SCED methodology is presented in [9,53] and similar to SCUC and RTUC, it has been extended to allow for the ramping of wind, solar, and hydro resources [9]. A more comprehensive description of the EPECS methodology and mathematical formulations for each control layer can be found in [9,53]. This methodology has been analyzed and validated by ISO-NE.

2.6. Regulation

A pseudo-steady-state approximation of the regulation service model that ties directly to a power flow model of the physical power grid is also used in this study. Normally, imbalances at the output of the regulation service would be represented in the form of frequency changes [60]. However, for steady-state simulations with 1-minute

Table 1
This table maps the SOARES 2030 scenarios to the ReEDS 2018 standard scenarios [59] that were used to evolve the SOARES 2030 scenario data into the 2040 scenarios used for this study.

Scenario Name	SOARES 2030 Scenarios	ReEDS Scenarios
Scenario 2040-1	RPSs + Gas	High RE Cost
Scenario 2040-2	ISO Queue	Accelerated Nuclear Retirements
Scenario 2040-3	Renewables Plus	Low RE Cost
Scenario 2040-4	No Retirements beyond Forward Capacity Auctions (FCA) #10	Low Wind Cost
Scenario 2040-5	ACPs + Gas	Extended Cost Recovery
Scenario 2040-6	Renewable Portfolio Standards (RPSs) + Geodiverse Renewables	Low Natural Gas Prices

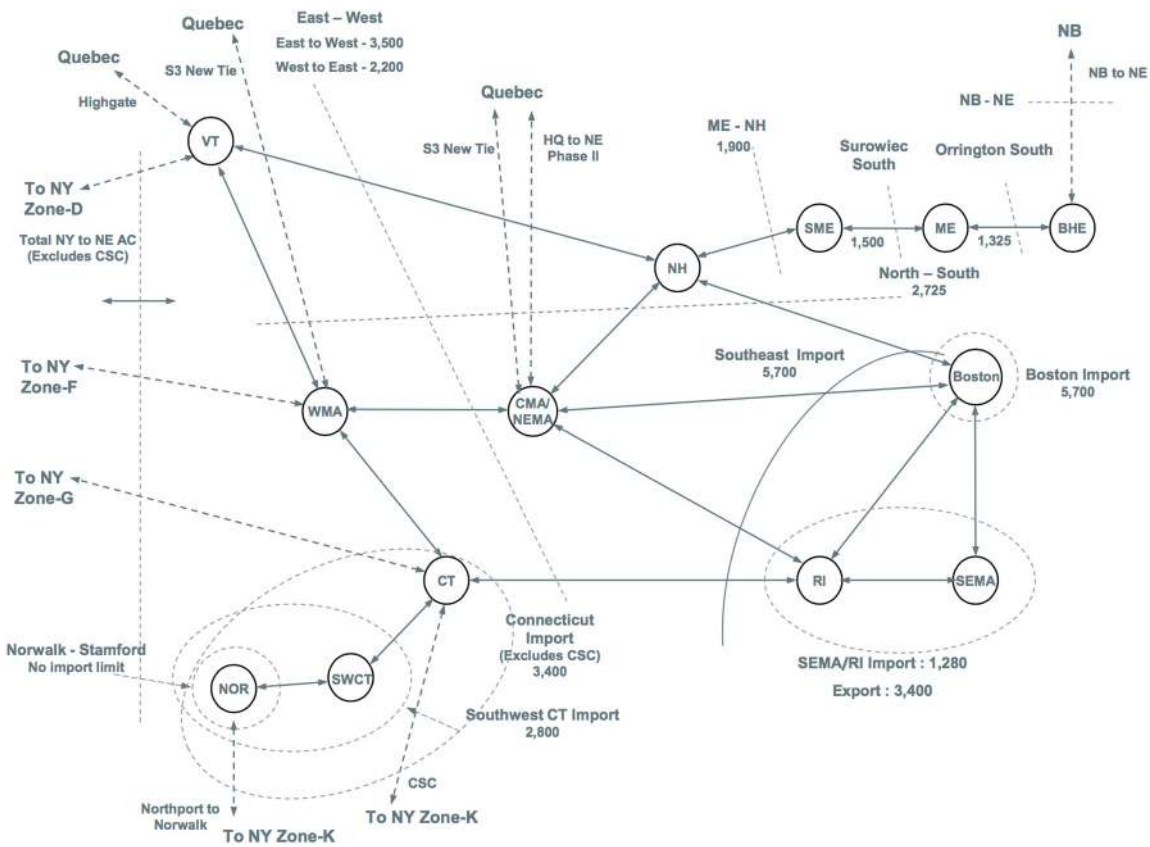

Fig. 5. The ISO-NE zonal network model represented as "pipes" and "bubbles"[53].

time step, the concept of frequency is not applicable. Instead, a designated *virtual* swing bus consumes the mismatches between generation and electricity load to make the steady state power flow equations solvable [53].

2.7. Variable renewable energy

Variable renewable energy resources in the EPECS simulator are studied as time-dependent, spatially distributed exogenous quantities that contribute directly to the electricity net load. Where the term *net load* here is defined as the difference between the aggregated electricity system load and the total generation produced by VREs, tieline profiles and any transmission losses [53].

As previously defined in [9], the EPECS simulator differentiates energy resources into several classes:

Definition 2.7.1 (*Variable Renewable Energy Resources (VREs)*)**.** Generation resources with a stochastic and intermittent power output. Wind, solar, run-of-river hydro, and tie-lines are assumed to be VREs.

Definition 2.7.2 (*Semi-Dispatchable Resources*)**.** Energy resources that can be dispatched downwards (i.e curtailed) from their uncurtailed power injection value. When curtailment is allowed for VREs, they become semi-dispatchable. In this study, wind, solar and tie-lines are treated as semi-dispatchable resources. Note that for the purposes of this study, electricity generated by run-of-river and conventional hydro resources can be curtailed and, therefore, these resources are treated as semi-dispatchable in the "flexible case" mentioned in Section 3.1. However, in the "conventional case", the electricity output of run-of-river and conventional hydro resources is *not* semi-dispatchable but rather variable. Similarly, water and wastewater treatment facilities have the ability to shed their electricity consumption in the "flexible case" and are inflexible or variable in the "conventional case".

Definition 2.7.3 (*Must-Run Resources*)**.** Generation resources that must run at their maximum output at all times. In this study, nuclear generation units are assumed to be *must run* resources.

Definition 2.7.4 (*Dispatchable Resources*)**.** Energy resources that can be dispatched up and down from their current value of power injection. In this study, all other resources are assumed to be dispatchable.

The EPECS simulator employs the operating reserve concepts described in [61,62] with only a few changes. This study focuses on the normal operating reserves that are able to respond to real-time changes in wind and solar generation. Specifically, how much of these reserve quantities comes from electricity generated by water resources such as conventional hydro and run-of-river hydro power plants, and the electricity load-shedding potential of electricity consumed by water and waste-water treatment facilities. Normal operating reserves are classified as load following, ramping, and regulation reserves based on the mechanisms upon which they are acquired and activated. For the purposes of this study, the curtailment of VREs was assumed to provide both load-following and ramping reserves in an upward direction to their forecasted value and in a downward direction to their minimum operating capacity limit.

These three types of operating reserves work together to respond to real-time forecast errors and variability in the electricity *net load* during normal system operation. Note that the actual quantities of these reserves are physical properties of the power system and exist regardless of whether they are monetized or not. The EPECS simulator provides as output the following quantities: system imbalances, operating reserves (load-following, ramping and regulation), generator set points, curtailed generation and line flows for every minute.

2.8. System-level Generic Model (SGEM)

The SGEM was developed to study the water use of fossil fuel, nuclear, geothermal and solar thermal power plants using either steam or combined cycle technologies [63]. This model is also geography and case-independent; making it ideal for application to the ISO-NE system. Three main cooling processes are applied in this paper: once-through cooling, wet tower cooling and dry-air cooling. Majority of the older generation power plants used once-through cooling technology while the newer power plants were either recirculating or dry-cooling. The formulae for computing water withdrawals and consumption are presented in [9].

With this information, the energy–water flows through the yellow system boundary of Fig. 2 can be easily quantified (as detailed in [9]) to determine, water withdrawals and consumption by thermal power plants, as well as other aspects such as fuel consumption and CO_2 emissions. As illustrated in Fig. 2, it is important to capture all the physical flows between the three physical infrastructures(water supply system, wastewater management system, and electricity supply system) and the natural surface environment. In this study, however, each water resource fits within an electric power system load area (or "bubble" as they commonly called within the New England Power Pool). Therefore, full hydraulic modeling does not provide additional insight in the provision of flexibility services to the electric power grid. The approach presented here is sufficient to capture all the interfaces between the water supply system and the electricity supply system and impose aggregate energy constraints as necessary.

2.9. Assessing the flexibility of the system

The term power system flexibility is quantified by assessing the availability of several different types of normal operating reserves namely; load-following, ramping, and regulation reserves. Together, these reserves determine how well the system can respond to real-time variability in the electricity system net load. The formulae for these reserves are established in the following Refs. [61,62,64]. Therefore, a system with abundant amounts of operating reserves is well-equipped to respond to real-time variability in electricity net load and is thus, considered to be more flexible.

3. Case study scenarios and data

3.1. Study scenarios

The case study scenarios presented in this work are best understood in the context of the twelve scenarios that were studied in the 2017 System Operational Analysis and Renewable Energy Integration Study (SOARES) that was commissioned by ISO-NE. These 12 scenarios distinguished between the amount and diversity of dispatchable generation resources, electricity load profiles, and the penetration of VREs [53]. Of these scenarios, six were meant to describe the year 2025 while the other six were meant to describe the year 2030. Both the 2025 and 2030 scenarios used in the SOARES were defined by ISO New England and its respective stakeholders. The ReEDS capacity expansion model was used to evolve the 2030 SOARES scenarios to the 2040 scenarios used in this work. To achieve this, the ReEDS capacity planning tool was first calibrated to reach the SOARES 2030 energy mixes from a 2015 base year. From there, the ReEDS model was extended along these six distinct trends (as outlined in Table 1) another 10 years into the future to 2040 to reach the energy mixes presented here. The final capacity mixes of the six 2040 scenarios are summarized in Fig. 6 and are described further below. Note that these scenarios are by no means a prediction of ISO New England's future energy mixes. They are simply indicative of the trends demonstrated by the SOARES 2030 scenarios if they were to continue another 10 years to 2040.

In order to assess the value of uncoordinated vs coordinated EWN operation, each of these six scenarios were simulated twice; once with energy–water resources as variable resources and another as semi-dispatchable resources. These scenario variants are respectively referred to as the "conventional" operating mode (as a control case) and the "flexible" operating mode (as the experimental case).

3.1.1. Scenario 2040-1: RPSs + gas

In this scenario, the oldest oil and coal generation units are retired by 2030 and the retired units are replaced by natural gas combined-cycle (NGCC) units at the same locations. Furthermore, the ReEDS model adds 50 MW of biomass, 233 MW of solar, 75MW of hydro and 6351 MW of natural gas (NG) to this scenario. It also retires 870 MW of nuclear, 667 MW of NG and 1127 MW of oil generation.

3.1.2. Scenario 2040-2: ISO queue

In this scenario, the retired oil and coal units from Scenario 1 are replaced by renewable energy resources instead of NGCC. The locations of the renewable energy resources are determined according to the ISO-NE Interconnection Queue. The ReEDS model resulted in the addition of 2498 MW of solar, 9.77 MW of hydro, and 5831.75 MW of NG (mostly in New Hampshire). In addition, 2471 MW of nuclear, 668 MW of natural gas and 25 MW of coal generation units were retired.

3.1.3. Scenario 2040-3: Renewables plus

In this scenario, more renewable energy resources are used to replace the retiring units. Additionally, battery energy systems, energy efficiency and plug-in hybrid electric vehicles (PHEV) are added to the system. Moreover, two new tie lines are added to increase the amounts of hydroelectricity imports. The ReEDS model results in the following modifications to this scenario: (1) addition of 2760 MW of solar, 9 MW of hydro, 2765 MW of NG, and (2) the retirement of 378 MW of coal, 870 MW nuclear, 667 MW of NG and 1127 MW of oil.

3.1.4. Scenario 2040-4: No retirements beyond Forward Capacity Auctions (FCA) #10

In contrast to other scenarios, no generation units are retired beyond the known FCA resources. The FCA resources are replaced by NGCC located at the Hub. This scenario is the *business-as-usual* scenario. The ReEDS model results in the following modifications to this scenario: (1) addition of 989 MW of solar, 4.2 MW of hydro, and 3987 MW of NG, and (2) the retirement of 383 MW of coal, 870 MW nuclear, 667 MW of NG and 1127 MW of oil.

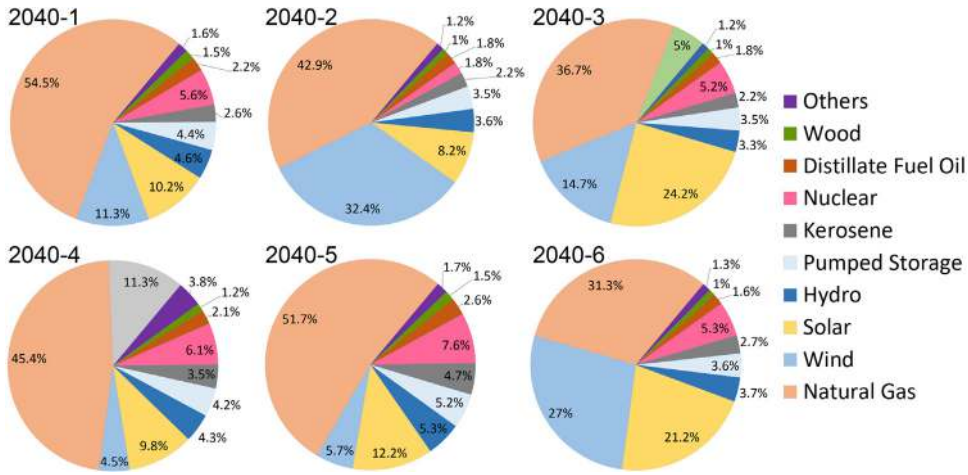

Fig. 6. Summary of available generation capacity as a percentage of total available capacity by fuel type for all six 2040 scenarios.

3.1.5. Scenario 2040-5: ACPs + gas

In this scenario, the oldest oil and coal generation units are retired by 2030 and these units are replaced by new NGCC units to meet the net Installed Capacity Requirement (NICR). The ReEDS model results in the following modifications to this scenario: (1) addition of 3089 MW of solar, 11.1 MW of hydro, and 2496 MW of NG, and (2) the retirement of 253 MW of coal, 870 MW nuclear, 667 MW of NG and 1127 MW of oil.

3.1.6. Scenario 2040-6: Renewable Portfolio Standards (RPSs) + geodiverse renewables

This scenario is similar to Scenario 5 but instead of replacing the retired units with NGCC units, additional renewable energy generation is used to meet the RPSs and the NICR. However, the solar PV and offshore wind units are located closer to the main electricity load centers while the onshore wind is located in a remote area in Maine. The ReEDS model results in the following modifications to this scenario: (1) addition of 3011 MW of solar, 6.2 MW of hydro, and 2430 MW of NG, and (2) the retirement of 870 MW nuclear, 667 MW of NG and 1127 MW of oil.

In addition to the changes in capacity mixes implemented in ReEDS, interface limits shown in Fig. 5 were raised to reflect the likely situation that New England would work to resolve line congestion found in the 2025 and 2030 scenarios in the SOARES scenarios [53]. Finally, in addition to the electric data, data on power consumption by water and waste-water treatment facilities as well as the cooling mechanisms of thermal generators were used to determine their share of the peak electricity load. The cooling data for thermal power plants was further enhanced by data from the Energy Information Agency's (EIA) databases [65–67].

3.2. Electricity net load profiles

The electricity net load profile comprised of the system electricity load profile minus the electricity generation from wind, solar, run-of-river and pond-hydro power plants, as well as tie-line flows between New England and other regions. Fig. 7 contrasts the electricity net load profile of Scenario 2040-4 as a "business-as-usual" case to that of Scenario 2040-3 as a high VRE case. The latter exhibits significant negative net load especially during low electricity load periods such as the Spring and Fall seasons. Fig. 8 summarizes the statistics of the electricity net load profiles for all six scenarios. The system electricity *peak load* for Scenarios 2040-1/2/4/5/6 was 28594 MW while that of Scenario 2040-3 was 22103 MW due to a higher penetration of energy efficiency measures. All scenarios had the same profile for electricity demand by water and wastewater treatment facilities. Run-of-river and pond-hydro generation profiles were curtailable at a price of $\$4.5/MWh$ similar to the 2017 ISO-NE SOARES. In this study, electricity consumed by water and wastewater treatment plants is treated as flexible in that it has a load-shedding rather than load-shifting capability and is assumed to contribute towards operating reserves. The 709 GWh of available pumped energy storage capacity is treated as dispatchable for all six scenarios throughout the study. Table 2 summarizes the capacity data for these flexible energy–water resources. Again, in order to assess the "flexibility value" of these energy–water resources, each of the six scenarios is simulated in a "conventional or uncoordinated" mode of operation and a "flexible or coordinated" mode of operation.

4. Results & discussion

Given the aforementioned scenarios, the value of flexible energy–water resources is assessed from reliability, economic, and environmental perspectives. From a reliability perspective, Section 4.1 presents the relative improvements in the system's balancing performance as quantified by the available quantities of operating reserves (i.e. load-following, ramping, and regulation reserves), curtailment, and the magnitude of system imbalances. From an environmental perspective, Section 4.2 quantifies the improvements in the quantities of water withdrawn and consumed as well as CO_2 emitted. Here, *water withdrawn* refers to the volumetric flow rate of water withdrawn from the natural surface environment and *water consumption* refers to the amount of water not returned to its original point of withdrawal (due to evaporative losses). Finally, Section 4.3 quantifies the associated production costs in the day-ahead and real-time energy markets.

4.1. Balancing performance of coordinated energy–water operation

As mentioned above, this section presents the system balancing performance improvements as result of coordinated energy–water operation in terms of: the available quantities of operating reserves (i.e. load-following, ramping, and regulation reserves), curtailment, and the magnitude of system imbalances.

4.1.1. Load-following reserves

In day-to-day operation, the upward and downward load-following reserves are used in time to allow the system to respond to variability and uncertainty in the electricity net load. In the traditional operation of the electricity grid, having sufficient load-following reserves is a primary concern especially in systems with high penetrations of renewables. Both upward and downward load-following reserves are equally important in ensuring system reliability. As upward load following

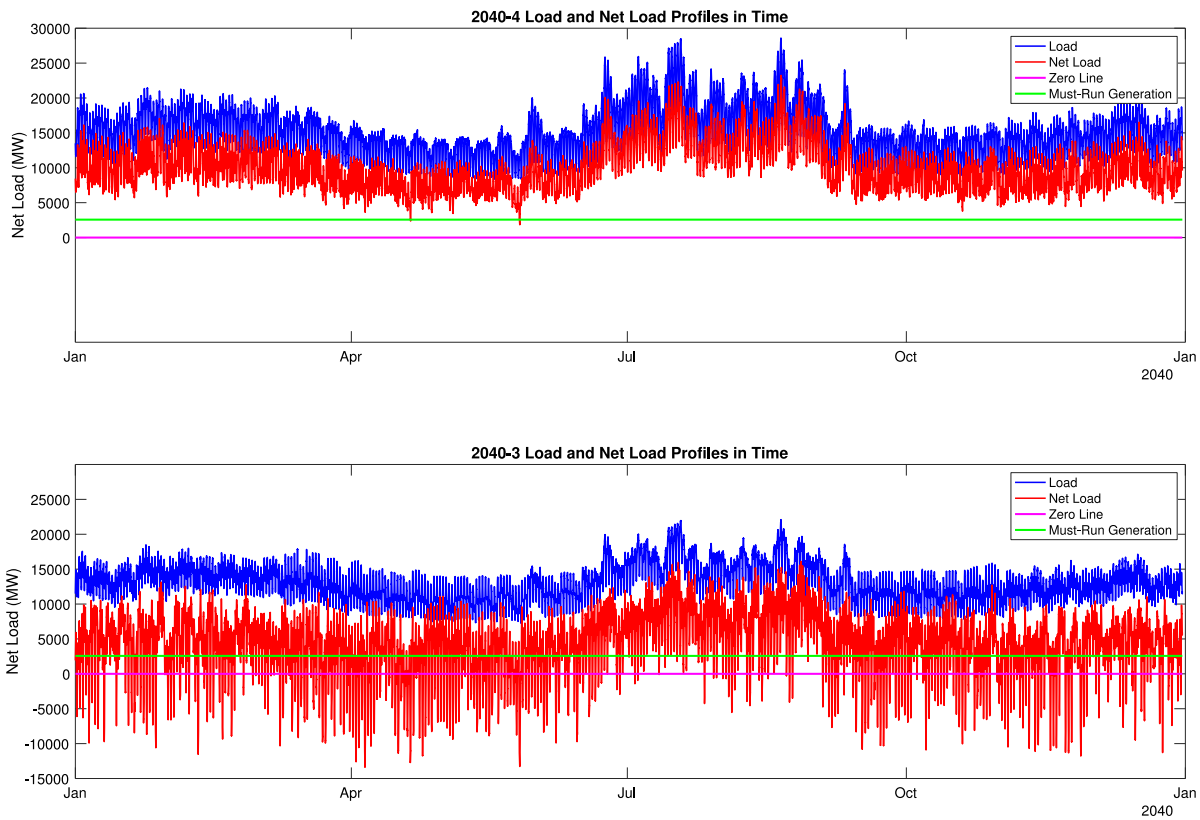

Fig. 7. The load and net load profiles from Scenario 2040-4 (top) and 2040-3 (bottom).

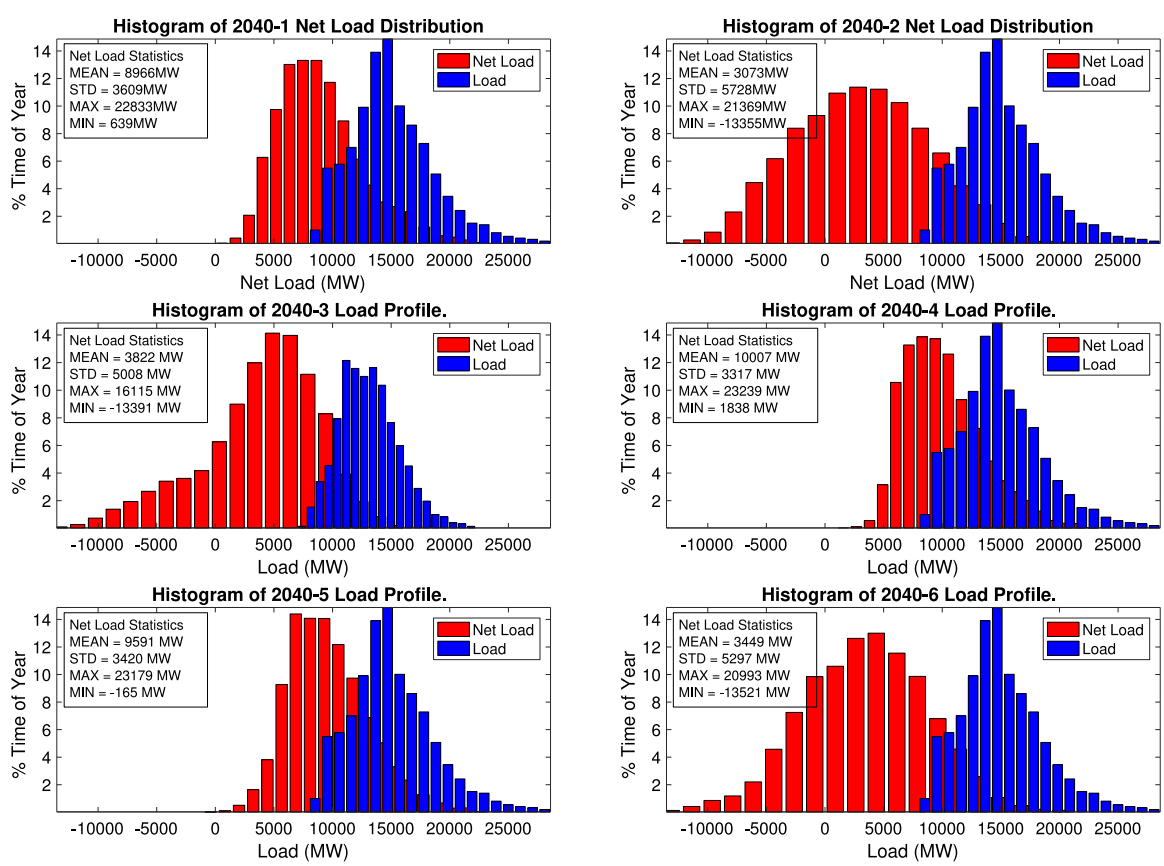

Fig. 8. A comparison of load and net load distributions for all six 2040 scenarios.

Table 2
A summary of available flexible water resources in the system as percentage of the peak load.

	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Hydro Run-of-River & Pond	1854MW (6.21%)	1788MW (5.99%)	1646MW (7.10%)	1782MW (5.97%)	1798MW (5.99%)	1784MW (5.97%)
Pumped Storage	1758MW (6.15%)	1758MW (6.15%)	1758MW (6.15%)	1758MW (6.15%)	1758MW (6.15%)	1758MW (6.15%)
Water Load	565MW (1.89%)	565MW (1.89%)	565MW (2.44%)	565MW (1.89%)	565MW (1.89%)	565MW (1.89%)
System Peak Load	28594 MW	28594 MW	22103MW	28594MW	28594 MW	28594 MW

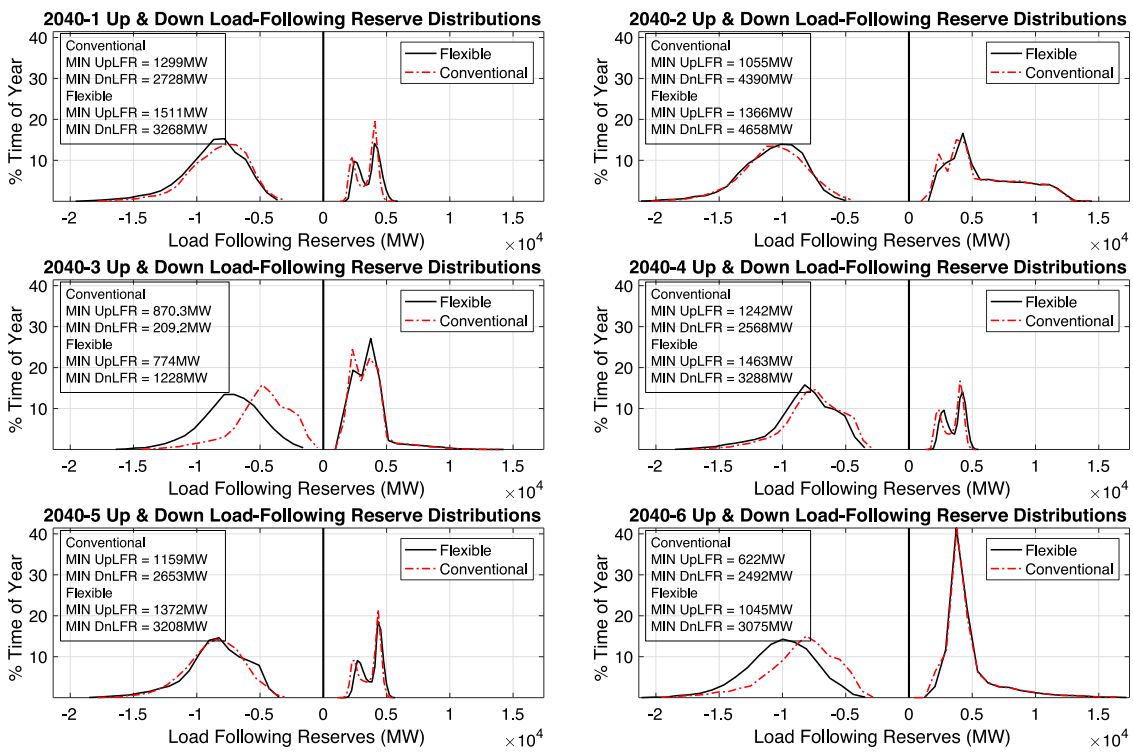

Fig. 9. Distributions of the available upward and downward load following reserves for all six 2040 scenarios in both the conventional and flexible operating modes.

Table 3
Change in downward and upward load-following reserves statistics (flexible *minus* conventional) for 2040 scenarios.

Δ LFR (MW)	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Up Mean	208.1 (5.77%)	171.7 (2.86%)	65.6 (1.83%)	207.1 (5.78%)	194.2 (5.08%)	57.7 (1.24%)
Up STD	8.4 (1.00%)	−55.6 (−1.94%)	−17.3 (−1.22%)	−42.1 (−5.32%)	−67.6 (−8.36%)	−36.09 (−1.74%)
Up Max	178.3 (3.07%)	228.3 (1.56%)	335.3 (2.32%)	242.5 (4.37%)	107.9 (1.92%)	686.8 (3.94%)
Up Min	211.9 (14.03%)	311.1 (22.77%)	−96.3 (−12.45%)	221.2 (15.12%)	212.6 (15.50%)	422.6 (40.46%)
Up 95 percentile[1]	241.1 (10.51%)	282.7 (11.59%)	6.0 (0.31%)	288.9 (12.35%)	294.6 (11.83%)	244.5 (9.15%)
Down Mean	743.8 (8.48%)	801.6 (7.41%)	925.5 (12.66%)	647.2 (7.83%)	744.0 (8.77%)	984.1 (9.68%)
Down STD	8.75 (0.36%)	16.29 (0.66%)	36.01 (1.52%)	2.98 (0.12%)	9.50 (0.39%)	67.97 (2.55%)
Down Max	1177.0 (6.11%)	932.5 (4.37%)	1678.0 (10.27%)	961.1 (5.22%)	1086.0 (5.79%)	1424.0 (6.77%)
Down Min	540.3 (16.53%)	267.9 (5.75%)	1019.0 (82.96%)	720.5 (21.91%)	554.9 (17.30%)	583.2 (18.97%)
Down 95 percentile	749.0 (13.96%)	790.6 (10.79%)	1026.0 (28.55%)	717.7 (14.73%)	750.7 (14.99%)	876.3 (14.43%)

Table 4
Change in downward and upward ramping reserves statistics (flexible *minus* conventional) for all six 2040 scenarios.

Δ RampR Stats (MW/min)	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Up Mean	334.9 (11.83%)	259.4 (5.28%)	291.3 (8.26%)	308.7 (13.78%)	325.3 (14.31%)	287.7 (6.16%)
Up STD	14.8 (2.86%)	27.9 (5.42%)	3.5 (0.31%)	16.3 (3.40%)	11.6 (2.55%)	15.8 (1.48%)
Up Max	430.7 (10.40%)	354.7 (5.65%)	271.0 (4.83%)	361.5 (10.43%)	372.9 (10.58%)	331.1 (4.79%)
Up Min	−59.3 (−3.89%)	69.7 (3.07%)	410.6 (47.32%)	−4.4 (−0.40%)	−5.6 (−0.49%)	305.1 (15.21%)
Up 95 percentile	310.6 (14.77%)	195.5 (4.68%)	314.9 (14.11%)	300.0 (18.78%)	318.0 (19.19%)	42.5 (1.28%)
Down Mean	339.7 (14.81%)	261.8 (5.86%)	292.3 (8.70%)	317.3 (18.35%)	325.8 (17.88%)	288.9 (6.50%)
Down STD	16.4 (3.69%)	21.4 (4.81%)	1.5 (0.13%)	16.1 (3.67%)	12.7 (2.94%)	12.4 (1.20%)
Down Min	294.2 (22.51%)	22.1 (1.06%)	199.7 (31.65%)	−15.1 (−1.92%)	−6.7 (−0.76%)	293.9 (18.44%)
Down Max	417.3 (15.37%)	354.3 (7.06%)	275.9 (5.64%)	385.1 (17.38%)	345.1 (14.42%)	320.7 (5.40%)
Down 95 percentile	344.3 (19.12%)	208.5 (5.31%)	308.0 (13.94%)	328.3 (26.15%)	337.4 (24.92%)	42.1 (1.32%)

Table 5
Change in the curtailment statistics (flexible *minus* conventional) for all six 2040 scenarios.

	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Tot. Semi-Disp. Res. (GWh)	0.00	0.00	0.00	0.00	0.00	0.00
Tot. Curtailed Semi-Disp. Energy (GWh)	17.71	−1.95	60.86	23.44	20.57	−6.18
% Semi-Disp. Energy Curtailed	0.03	−0.00	0.07	0.05	0.04	−0.01
% Time Curtailed	−10.42	−2.67	−5.97	−10.90	−10.74	−3.08
Max Curtailment Level (MW)	1.82	2.68	330.16	−63.03	−1.81	397.67

reserves are exhausted (approach zero), the ability of the system to respond to fluctuation in the electricity net load is constrained.

Therefore, an enhanced balancing performance with respect to load following reserves would show a significant trough around the zero LFR-axis in the distributions of load following reserves shown in Fig. 9. The larger the trough is, the more the system is not using its load following reserves to balance the system. Fig. 9 shows that the flexible use of energy–water resources (in black) widens the trough of load-following reserves around the zero line relative to conventional operation (in red). These graphical results are confirmed numerically in Table 3. Flexible operation enhances the mean values of the upward and downward load following reserves (treated as separate distributions) by 1.24%–12.66% across all six scenarios. Furthermore, the minimum upward and downward load following reserves are improved by flexible operation by 5.75%–82.96% across all but one of the six scenarios. The minimum statistic is particularly important because it defines a type of worst case "safety margin" that the system will always have available to ensure its security. Similarly the 95 percentile statistic gives a measure of how much this minimum level increases when 5% of the distribution is treated as abnormal outlier behavior. The simulations show improvements in the 95 percentile statistic of 0.13–28.55% across all six scenarios; thus demonstrating its robustness to not just the minimum worst-case point but also the distribution tail that represents challenging periods of operation. The maximum and standard deviation statistics are provided for completeness.

4.1.2. Ramping reserves

Ramping reserves describe the total amount of power that the system can respond up or down within a minute. Traditionally, only dispatchable resources are assumed to contribute towards ramping reserves. In this study, renewable energy resources are semi-dispatchable by virtue of curtailment. Consequently, they are assumed to not just be able to ramp down or up to their minimum or maximum values but also do so within five minutes given their power-electronics based control. Five minutes, in this case, coincide with the minimum time-step used in the real-time market. Similar to load-following reserves, ramping reserves are key to ensuring that the system can respond in time to fluctuations in the electricity net load. Having sufficient amounts of both upward and downward ramping reserves is equally important to ensuring reliable performance. As the amount of ramping reserves approaches zero, the ability of the system to respond to net load variability is significantly diminished.

Table 6
Change in regulation reserves statistics (flexible *minus* conventional) for all six 2040 scenarios.

	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
% Time Reg. Res Exhausted	0.001	0.001	0.000	0.000	0.001	0.001
Reg. Res. Mileage (GWh)	1.800	0.354	0.788	1.014	1.190	0.468
% Reg. Res. Mileage	1.349	0.251	0.638	0.777	0.909	0.326

Similar to load-following reserves, both upward and downward ramping reserves are enhanced through the flexible operation of energy–water resources. Fig. 10 illustrates a widened trough in the

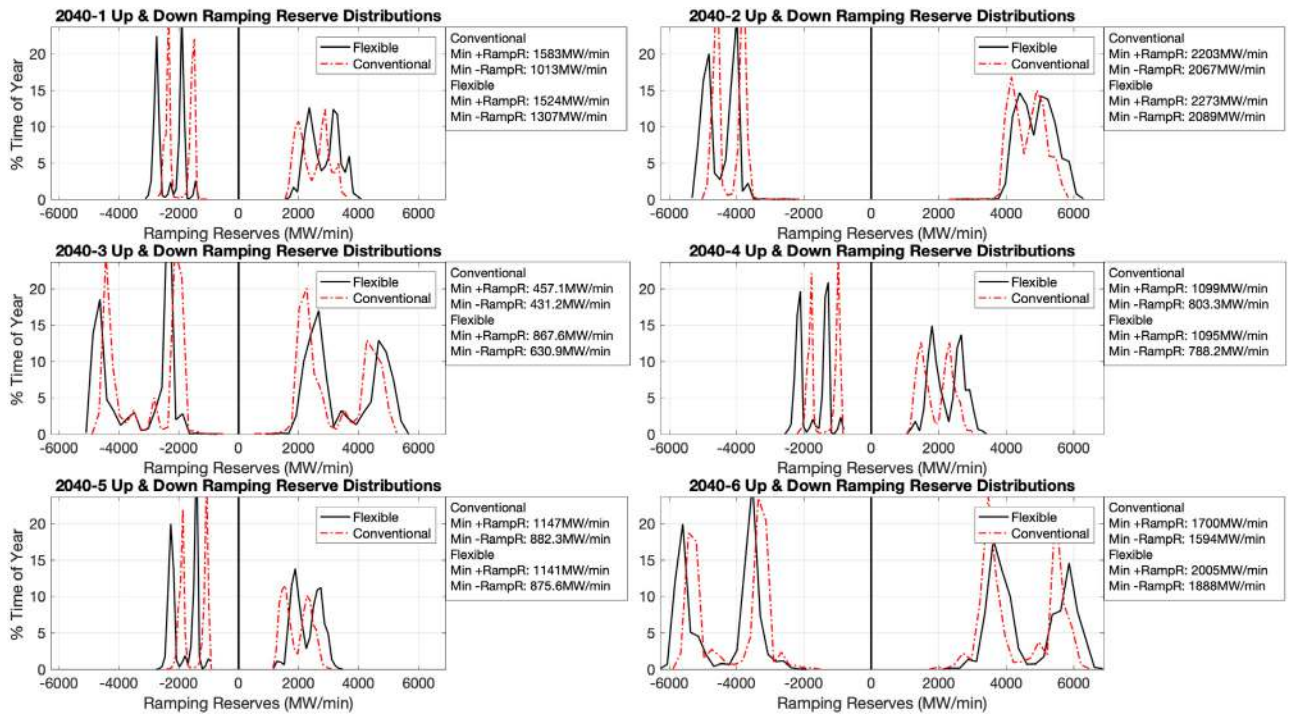

Fig. 10. Distributions of the available upward and downward ramping reserves for all six 2040 scenarios in both the flexible and conventional operating modes.

flexible operating mode relative to the conventional mode. This observation is supported by the statistics in Table 4. The mean value for the upward ramping reserves is improved across all scenarios by up to 14.31%. Likewise, the mean downward ramping reserves are improved by up to 18.35%. Another key measure of sufficient ramping reserves is the minimum level. As illustrated in Table 4, flexible operation enhances the minimum downward ramping reserves by 31.65% and the minimum upward ramping reserves by a maximum of 47.32%. However, in cases with a lower penetration of VREs such as scenarios 2040-1/4/5, the minimum levels are slightly worse in the flexible case than in the conventional case. Despite these anomalies, flexible operation improved 95% percentile levels of upward and downward ramping reserves in all cases (by 1.28%–26.15%). These results show that the curtailment of VREs increases the flexibility to the system if they are used to provide ramping reserves. A complete summary of ramping reserves statistics for all six scenarios is found in Table 4.

4.1.3. Curtailment

By definition, flexible energy–water resources increase the amount of generation available for curtailment. Recall that by Definition 2.7.2, run-of-river and conventional hydro-pond resources are semi-dispatchable resources that can be curtailed in a flexible operating mode. As illustrated in Fig. 11, scenarios with a lower penetration of VREs such as scenario 2040-1/4/5 curtail infrequently and the amount of megawatt curtailed is generally zero. For scenarios 2040-2/3/6, curtailment is used at least 40% of the time. Although, the two cases appear to have similar curtailment levels, a closer look at Table 5 shows that the flexible case curtails for a smaller percentage of the year (2.67%–10.9%) less than the conventional case. Furthermore, the two operating modes show nearly identical levels of total curtailed energy. In the absence of sufficient load-following and ramping reserves, curtailment serves a key role in ensuring system balance. This role is particularly crucial for VREs located in remote areas (e.g. Maine) where it serves as the only control option given topological constraints and distance from electricity load areas.

4.1.4. Regulation service

The regulation service is used to correct system imbalances in real-time. This control lever is used to meet any left-over imbalances after curtailment, load-following and ramping reserves have been used up during market operation. In both cases, all scenarios appear to use their regulation effectively as shown in Fig. 12. This is indicative of a system that has sufficient regulation to mitigate real-time imbalances and maintain balancing performance. A closer inspection of Table 6 illustrates that flexible operation marginally increases the reliance on regulation (as shown by the excess mileage) and exhausts its regulation (albeit for a small fraction of the year 0.001) for all but scenarios 2040-3 and 2040-4.

4.1.5. System imbalances

Balancing performance indicates the residual imbalances after the regulation service has been deployed. Given that the regulation service was barely saturated, the amount of imbalances are expected to be minimal. As shown in Fig. 13, flexible energy–water resources had a small impact on the range of final imbalances of the system. Both systems appear to perform similarly with all cases maintaining a standard deviation of less than 16MW across all six scenarios. Table 7 illustrates that the flexible operating mode performs slightly better than the conventional with up to a 6.48% improvement in standard deviation. The minimum imbalances are lower in all cases except for Scenarios 2040-1 and 2040-2. Similarly, the maximum imbalances are lower for the flexible operating mode except for Scenarios 2040-2 and 2040-6 which represent scenarios with high VREs.

4.2. Environmental performance of coordinated energy–water operation

As mentioned before, the environmental performance of coordinated energy–water operation is assessed through overall reductions in water withdrawals, consumption and CO_2 emissions.

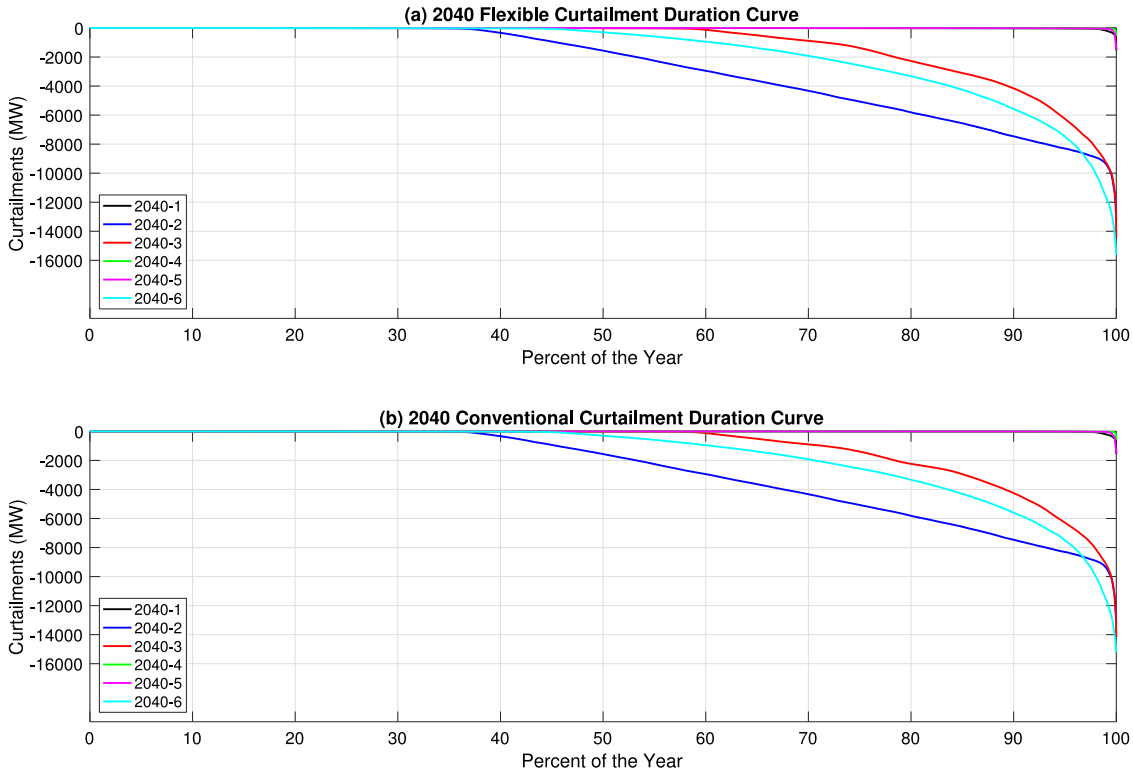

Fig. 11. Curtailment duration curves for all six 2040 scenarios in both the flexible (above) and conventional (below) operating modes.

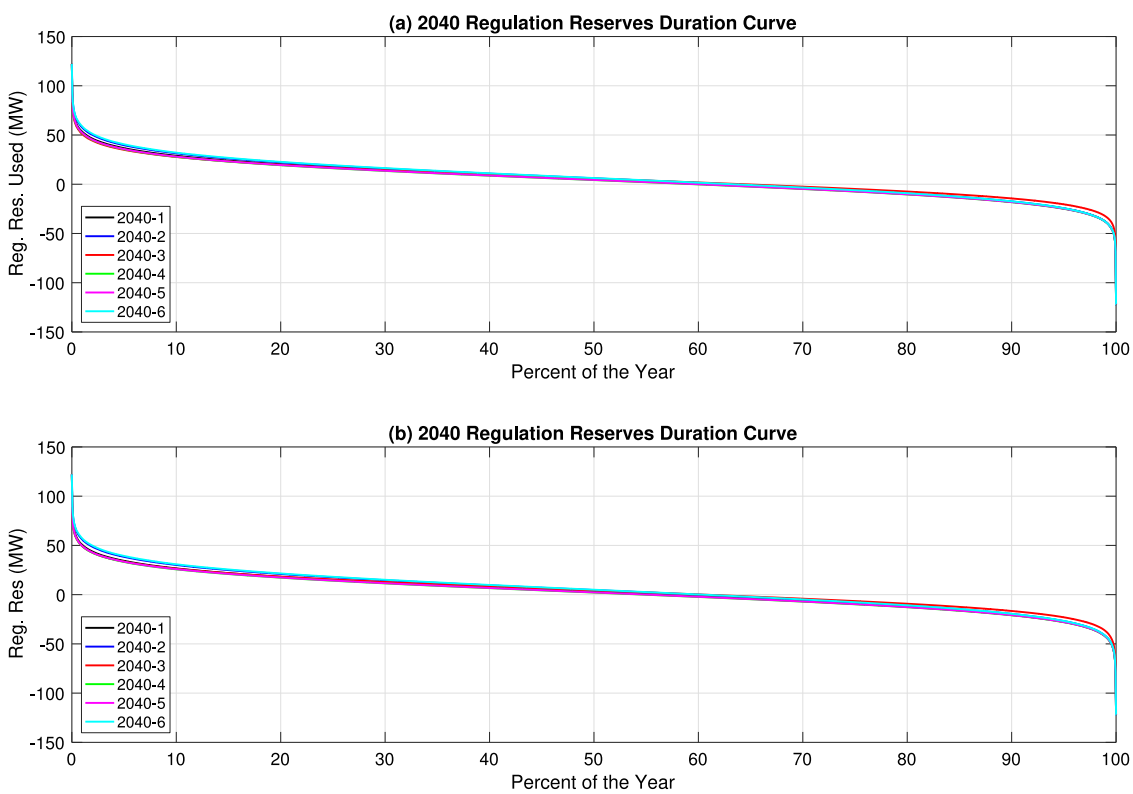

Fig. 12. Regulation duration curves for all six 2040 scenarios in both the flexible (above) and conventional (below) operating modes.

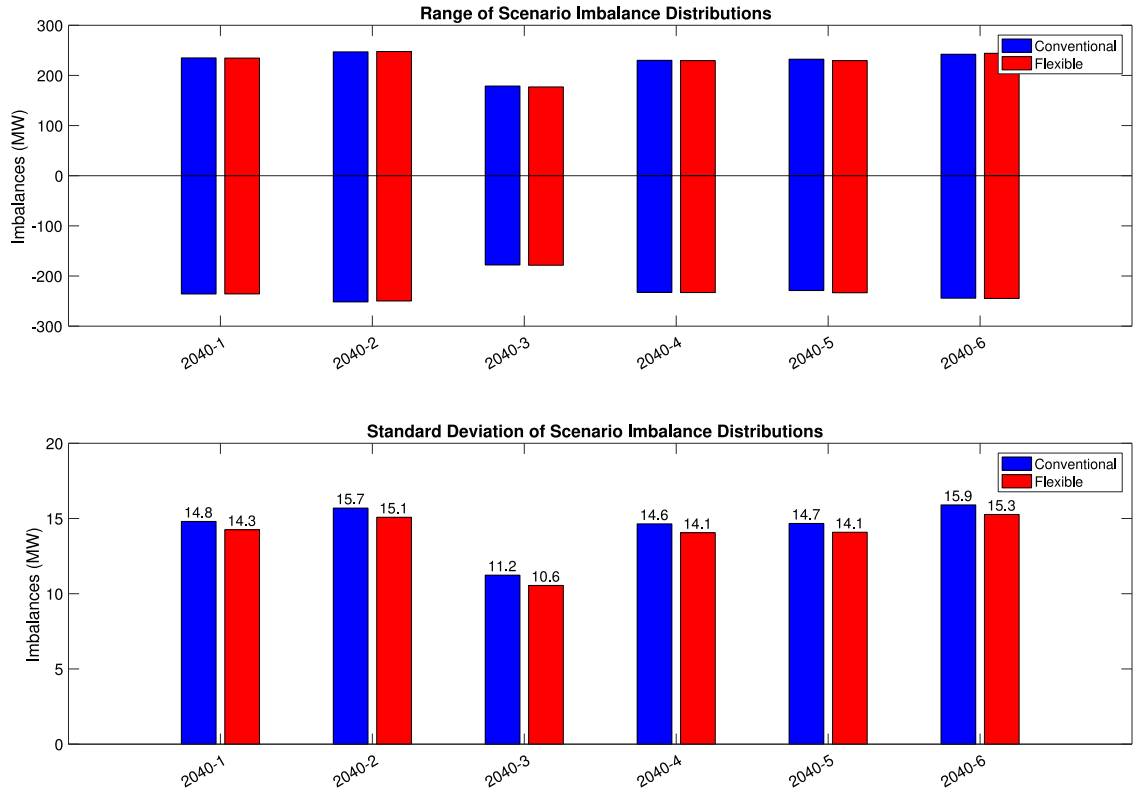

Fig. 13. Range (above) and standard deviation (below) statistics for all six 2050 scenarios in both the flexible (red) and conventional (blue) operation modes.

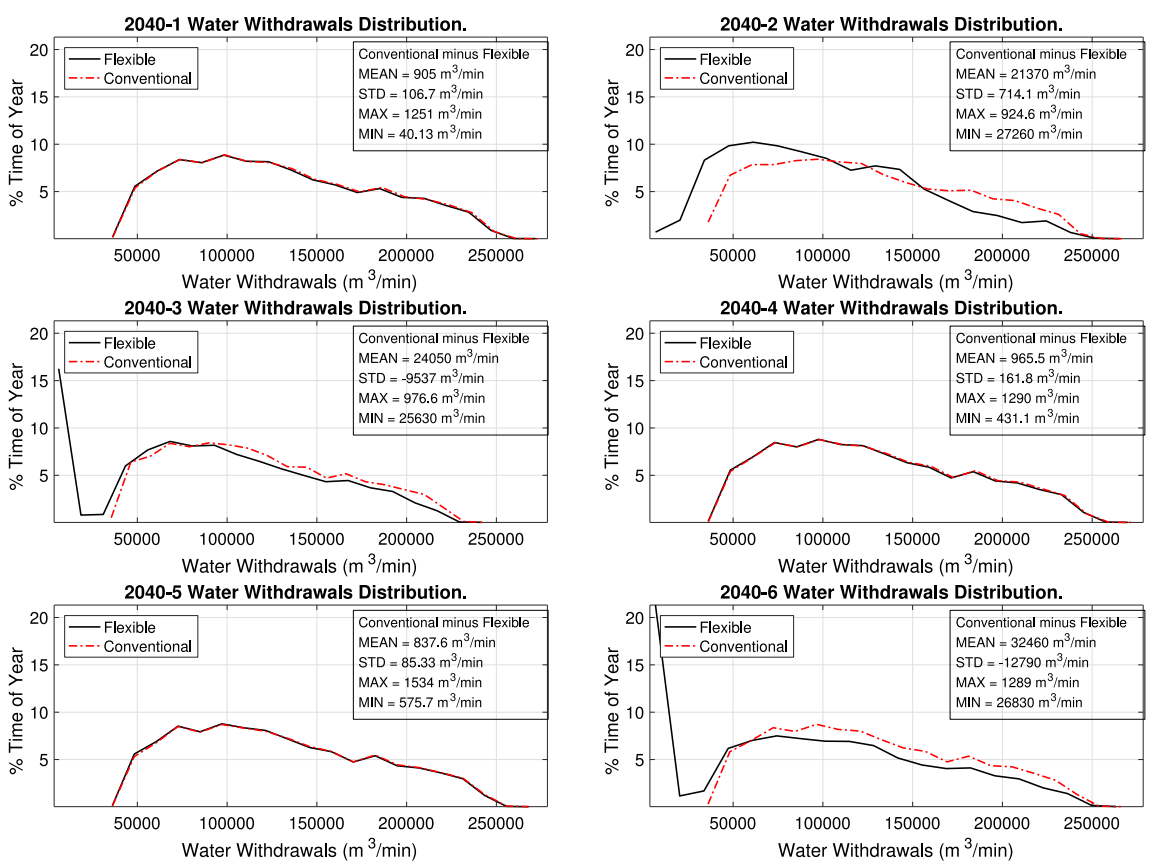

Fig. 14. Distributions of water withdrawals for all six 2040 scenarios in both the flexible and conventional operating modes.

Table 7
Change in range and standard deviations of imbalances (flexible *minus* conventional) for all six 2040 scenarios.

Change in Imbalance	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Max (MW)	−0.384	0.597	−1.767	−0.682	−2.911	1.902
% Max	−0.164	0.241	−0.998	−0.297	−1.269	0.779
Min (MW)	0.118	1.831	−0.598	−0.363	−4.405	−0.462
% Min	−0.050	−0.733	0.335	0.156	1.887	0.189
Std. (MW)	−0.552	−0.611	−0.684	−0.589	−0.584	−0.634
% Std.	−3.874	−4.052	−6.484	−4.188	−4.147	−4.155

4.2.1. Water withdrawals

Fig. 14 shows the water withdrawal distributions for the flexible and conventional operating modes. Flexible operation results in significantly lower withdrawals compared to conventional operation because the flexible energy–water resources are able to offset the use of thermoelectric power plants in favor of VREs. This phenomena is seen in how the flexible withdrawal distributions are shifted left towards zero. The associated water withdrawal statistics are summarized in Table 8 indicating improvements in mean withdrawals of up to 25.58%. These improvements are most pronounced in Scenarios 2040-2/3/6 with high penetrations of VREs. Indeed, the integration of several percent (on a capacity basis) of flexible energy–water resources as shown in Table 2, serves to reduce water withdrawals by many multiples of that percentage. Such a phenomena can potentially appear in any scenario where VRE curtailment serves as a major lever of balancing control. Nevertheless, the flexible operation of energy–water resources reduces water withdrawals across all six scenarios.

4.2.2. Water consumption

Electric power system water consumption occurs through the evaporative losses from cooling towers in recirculating cooling systems. Fig. 15 shows the water consumption distribution for both the conventional and flexible operating modes. While the effect is not large, the flexible mode of operation shifts the distribution slightly towards the zero mark. Specifically, flexible operation consumes 1.07–4.51% less water than the conventional operation across all six scenarios, as shown in Table 9. This relatively small percentage nevertheless accounts for $258 \times 10^3 m^3$ of water saved every year. Scenarios 2040-3 and 2040-6 have the least savings. Due to high penetrations of VREs, these scenarios require faster ramping generation which mostly comes from fast-ramping natural gas units with recirculating cooling systems. In short, the water saving effect of integrating VREs is a diminished to a certain extent by the need for operating reserves from water-consuming but flexible NGCC plants. If demand side resources (from electricity consumed by water and wastewater treatment plants or otherwise) played a large balancing role, then the water saving role of integrating VREs would be more pronounced.

4.2.3. CO_2 emissions

Finally, as shown in Fig. 16, the overall CO_2 emissions are significantly reduced through flexible operation. It reduces the overall CO_2 emissions by 2.10%–3.46%, as shown in Table 10. The mean, max, and standard deviation of emissions are all improved. This CO_2 emissions reduction occurs because flexible energy–water resources 1.) eliminate the need for some generation through reduced electricity consumption, 2.) enable greater VRE generation through a reduction in curtailment and 3.) displace fossil-fueled conventional generation.

4.3. Economic performance of coordinated energy–water operation

The economic performance of coordinated energy–water operation is assessed in terms of the day-ahead and real-time production costs.

4.3.1. Day-ahead energy market production costs

Fig. 17 shows flexible operation reduced the total production cost in the day-ahead energy market for all 2040 scenarios. Table 11 summarizes the associated statistics. Flexible operation reduced total production costs by 29.3–68.09M$ or between 1.22–1.76%. As illustrated in Fig. 17, Scenarios 2040-2/3/6 have much lower day-ahead production costs due to a high penetration of VREs. In contrast, scenarios 2040-1/4/5 have significantly higher costs as they are forced to commit expensive thermal power plants. In short, the day-ahead energy market production costs are lower because the flexible mode of operation represents an optimization program that is less constrained than the program associated with the conventional mode of operation.

4.3.2. Real-time energy market production costs

Fig. 18 illustrates the total real-time energy market production cost for all six scenarios. Similar to the day-ahead energy market, Scenarios 2040-1/4/5 have significantly higher production costs as they are forced to dispatch more expensive thermal power plants. Meanwhile, Scenarios 2040-2/3/6 have lower real-time energy market production costs due to a greater utilization of renewable energy. As detailed in Table 12, flexible operation reduces the average real-time market production costs by 2.46%–3.70% (or 19.58-70.83M$) across all six scenarios.

4.4. Discussion

This study provides results for six 2040 scenarios for the New England energy–water nexus. It illustrates significant improvements in balancing performance of the electricity system that arise from two key methodological differences from [53] namely; (1) treating energy–water resources as flexible, and (2) allowing solar and wind to provide load-following, and ramping reserves. These two changes in how resources are treated within electricity markets amount to significant improvements in overall minimum load-following and ramping reserves that ensure the system is able to better respond to variability in the net load. Compared to the renewable energy integration study in [53], the approach in this work results in overall lower curtailment

Table 8
Change in water withdrawals statistics (conventional *minus* flexible) for all six 2040 scenarios.

ΔH_20 Withdrawals	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Mean (m^3/min)	905.0 (0.70%)	21370.0 (17.29%)	24050.0 (20.59%)	965.5 (0.74%)	837.6 (0.65%)	32460.0 (25.58%)
STD (m^3/min)	106.7 (0.20%)	714.1 (1.35%)	−9537.0 (−19.92%)	161.8 (0.31%)	85.3 (0.16%)	−12790.0 (−24.40%)
Max (m^3/min)	1251.0 (0.45%)	924.6 (0.34%)	976.6 (0.39%)	1290.0 (0.47%)	1534.0 (0.56%)	1289.0 (0.47%)
Min (m^3/min)	40.1 (0.11%)	27260.0 (88.22%)	25630.0 (75.82%)	431.1 (1.17%)	575.7 (1.54%)	26830.0 (75.99%)
Total (m^3/min $\times 10^6$)	475.7	11230.0	12640.0	507.5	440.2	18090.0
Percent change (%)	0.70	17.29	20.59	0.74	0.65	25.58

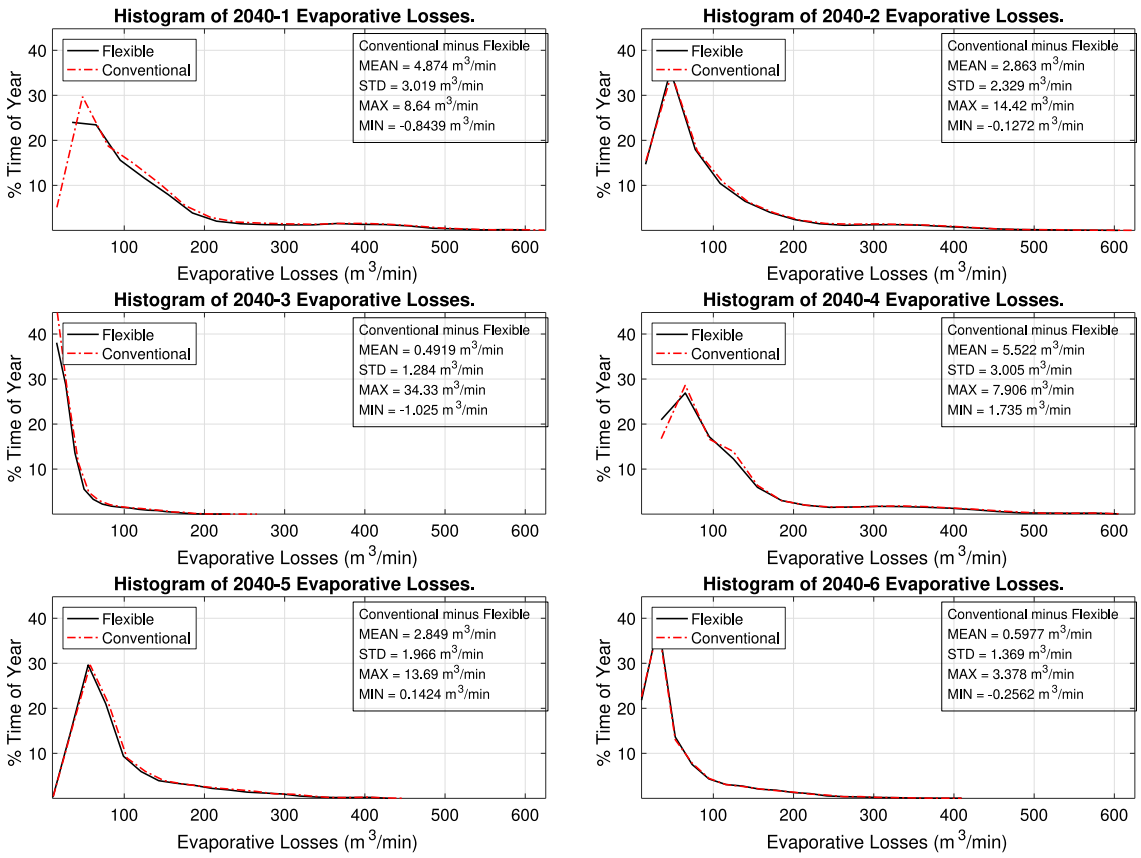

Fig. 15. Distributions of water consumption for all six 2040 scenarios in both the flexible and conventional operating modes.

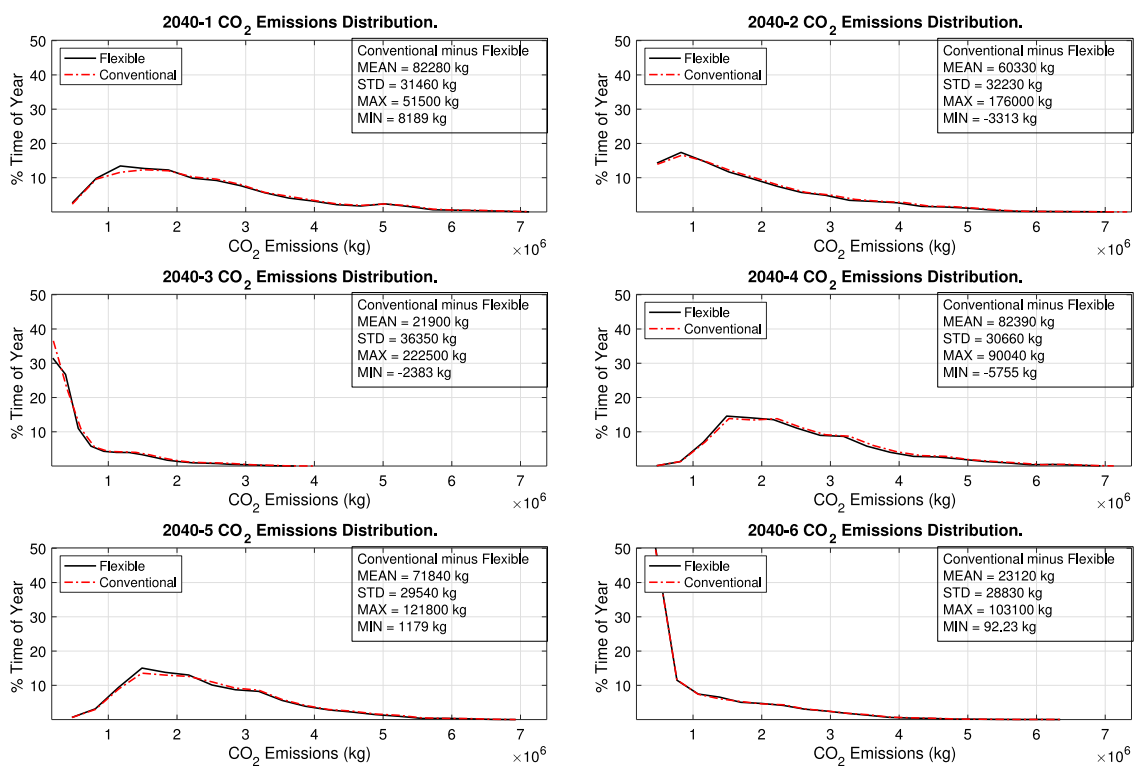

Fig. 16. Distributions of CO_2 emissions for all six 2040 scenarios in both the flexible and conventional operating modes.

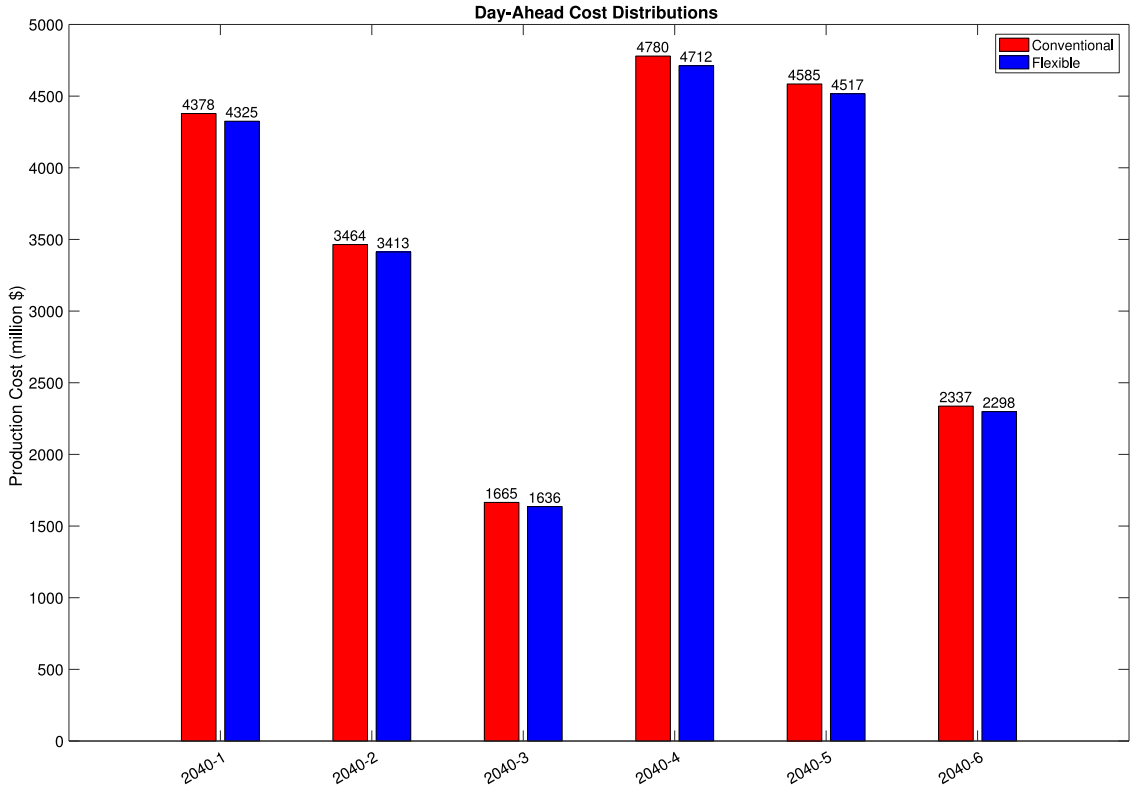

Fig. 17. Total production cost in the day-ahead energy market for all 2040 scenarios in both the flexible and conventional operating modes.

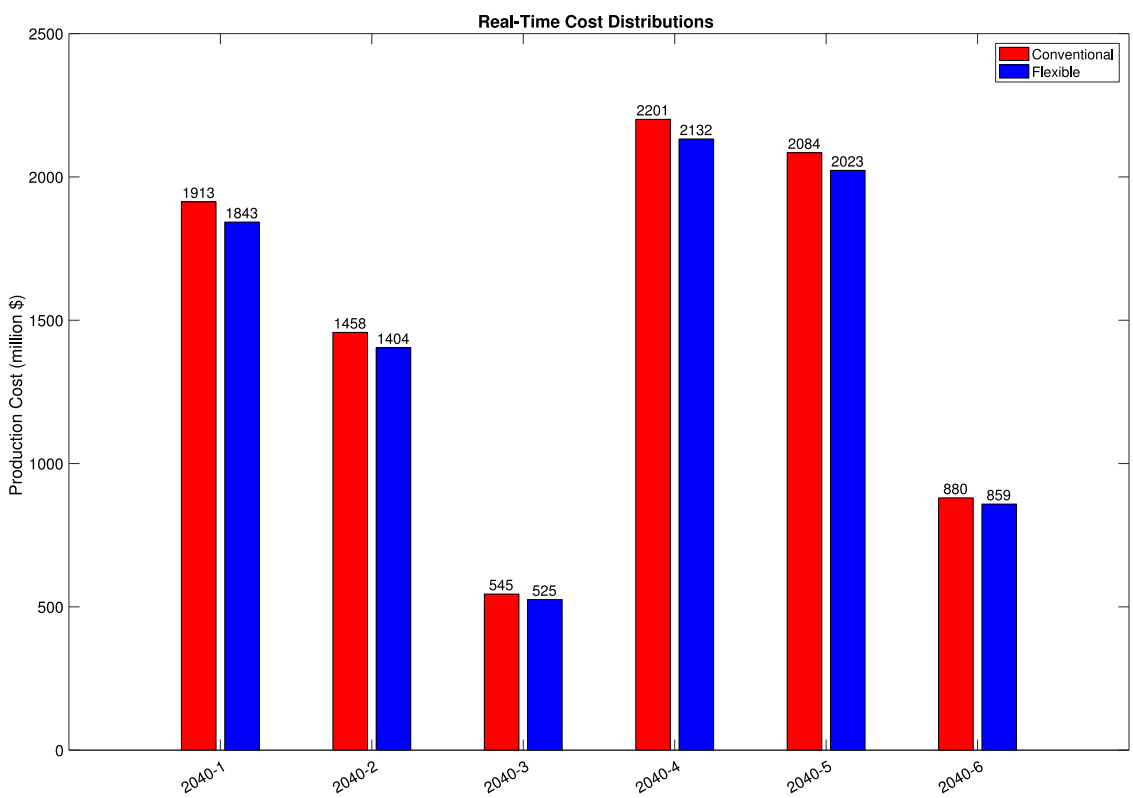

Fig. 18. A comparison of the real-time production costs for flexible and conventional operation.

Table 9
Change in evaporative loss statistics (conventional *minus* flexible) for all six 2040 scenarios.

Δ Evap Losses	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Mean (m^3/min)	2.67 (3.96%)	1.63 (3.11%)	0.30 (1.44%)	3.37 (5.03%)	1.51 (2.84%)	0.31 (1.03%)
STD (m^3/min)	1.10 (2.77%)	1.05 (2.97%)	0.74 (5.58%)	1.23 (3.33%)	0.61 (2.61%)	0.68 (3.05%)
Max (m^3/min)	5.71 (2.45%)	3.42 (1.44%)	6.40 (6.02%)	−0.00 (−0.00%)	1.80 (1.11%)	0.07 (0.04%)
Min (m^3/min)	−0.62 (−3.50%)	−0.00 (−0.00%)	−0.13 (−1.65%)	0.47 (2.56%)	−0.12 (−0.83%)	−0.06 (−0.52%)
Total ($m^3 \times 10^3$)	1402	859	158	1769	794	165
Percent change (%)	4.12	3.21	1.46	5.30	2.92	1.03

Table 10
Change in CO_2 emissions statistics (flexible *minus* conventional) for all six 2040 scenarios.

ΔCO_2 Emissions	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Mean (kg)	82 280 (3.46%)	60 330 (3.28%)	21 900 (3.17%)	82 390 (3.11%)	71 840 (2.90%)	23 120 (2.10%)
STD (kg)	31460.0 (2.44%)	32230.0 (2.66%)	36350.0 (5.75%)	30660.0 (2.69%)	29540.0 (2.71%)	28 830 (2.96%)
Max (kg)	51 500 (0.71%)	176 000 (2.38%)	222 500 (5.54%)	90 040 (1.26%)	121 800 (1.72%)	103 100 (1.59%)
Min (kg)	8189.00 (2.07%)	−3313.00 (−1.08%)	−2383.00 (−1.35%)	−5755.00 (−1.14%)	1179.00 (0.31%)	92.23 (0.03%)
Total (kg × 10^6)	43 240	31 710	11 510	43 300	37 760	12 150
Percent change (%)	3.46	3.28	3.17	3.11	2.90	2.10

Table 11
Change in day-ahead energy market production cost statistics (flexible *minus* conventional) for all six 2040 scenarios.

Δ Day-Ahead Costs	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Mean ($/h)	6115.1 (1.22%)	5909.4 (1.49%)	3345.2 (1.76%)	7712.7 (1.41%)	7773.1 (1.49%)	4388.1 (1.64%)
STD ($/h)	4859.0 (2.09%)	4355.7 (1.89%)	5336.3 (3.89%)	5327.3 (2.62%)	6160.9 (3.05%)	6095.2 (3.02%)
Max ($/h)	−16071.5 (−0.95%)	38820.1 (2.65%)	66093.4 (5.44%)	−76701.8 (−4.56%)	15683.0 (0.83%)	476535.0 (23.20%)
Min ($/h)	19290.1 (18.95%)	−2738.0 (−3.14%)	15922.7 (19.18%)	−706.4 (−0.45%)	−419.0 (−0.36%)	−10860.0 (−12.17%)
Total (million $)	53.57	51.77	29.30	67.56	68.09	38.44
% Reduction	1.22	1.49	1.76	1.41	1.49	1.64

Table 12
A summary of the real-time production cost statistics (flexible *minus* conventional).

Δ Real-Time Cost	2040-1	2040-2	2040-3	2040-4	2040-5	2040-6
Mean ($/min)	1347.5 (3.70%)	1013.5 (3.65%)	372.5 (3.59%)	1304.9 (3.12%)	1173.1 (2.96%)	412.5 (2.46%)
STD ($/min)	493.5 (2.31%)	533.2 (2.62%)	553.8 (5.21%)	497.8 (2.58%)	545.8 (2.90%)	536.9 (3.30%)
Max ($/min)	895.8 (0.58%)	3976.9 (2.69%)	385.2 (0.36%)	3163.4 (2.02%)	−5845.8 (−3.41%)	40662.3 (23.52%)
Min ($/min)	88.4 (2.76%)	75.5 (3.45%)	−0.0 (−0.00%)	65.3 (0.98%)	−0.0 (−0.00%)	157.3 (3.78%)
Total (million $)	70.83	53.27	19.58	68.58	61.66	21.7
% Reduction	3.70	3.65	3.59	3.12	2.96	2.46

levels and therefore, greater utilization of VREs. While these two studies cannot be compared one-to-one given that they used different data sets, the greater utilization of renewables in this work shows the significant value of flexible energy–water resources. The simulation results also show that flexible operation improves environmental performance of the electricity grid by reducing water withdrawals and consumption, and total CO_2 emissions of the system. Greater utilization of VREs in turn decreases the day-ahead and real-time market production costs. These results indicate that the study of renewable energy integration must leverage the value of demand-side resources (such as demand-side energy–water resources) in order to sustain higher penetrations of VREs. Furthermore, it shows that there is significant economic, environmental as well as reliability value in jointly studying/operating

Table 13
Balanced Sustainability Scorecard: The range of ***improvements*** caused by coordinated flexible operation of the EWN.

Balancing Performance	
Average Load Following Reserves	1.24–12.66%
Average Ramping Reserves	5.28–18.35%
Percent Time Curtailed	2.67–10.90%
Percent Time Exhausted Regulation Reserves	0%
Std. Dev. of Imbalances	3.874–6.484%
Environmental Performance	
Total Water Withdrawals	0.65–25.58%
Total Water Consumption	1.03–5.30%
Total CO_2 Emissions	2.10–3.46%
Economic Performance	
Total Day-Ahead Energy Market Production Cost	29.30–68.09M$
Total Real-Time Energy Market Production Cost	19.58–70.83M$

interdependent infrastructures such as the energy and water supply systems.

5. Conclusion

This work has used a novel enterprise control assessment methodology to study the EWN for the ISO New England System. Six scenarios were studied representing plausible electric power capacity mixes in 2040. The study specifically sought to understand the impact of flexible coordinated operation of energy–water resources on the holistic behavior of these six scenarios. In short, the flexible operation energy–water resources demonstrated truly "sustainable synergies" with respect to balancing, environmental, and economic performance. Table 13 summarizes the most important results of the study in a balanced sustainability scorecard and highlights the synergistic improvements caused by flexible coordinated operation of the EWN. Flexible operation of energy–water resources results in up to 12.66% improvements in load-following reserves, up to 18.35% increase in available ramping reserves and up to 10.90% reduction in the total time that curtailment of VREs occurs. Additionally, the environmental performance of the system is significantly improved with flexible operation resulting in up to 25.58% reductions in water withdrawals, 5.30% reductions in water consumption and up to 3.46% reductions in carbon dioxide emissions. These results show that as VRE resources become an ever-important part of the electric power system landscape, so too must the electric power system evolve to engage energy–water resources as control levers. In some cases, such resources – like hydro-power plants – are mainstays of traditional operation. In other cases, particularly water utility electric loads, these resources will have to evolve their operation to become true electric power grid participants.

CRediT authorship contribution statement

Steffi Olesi Muhanji: Data curation, Writing - original draft, Software, Validation, Visualization, Investigation, Formal analysis. **Clayton Barrows:** Funding acquisition, Data curation, Writing - review & editing. **Jordan Macknick:** Funding acquisition, Data curation, Writing - review & editing. **Amro M. Farid:** Funding acquisition, Project administration, Conceptualization, Methodology, Supervision, Writing - review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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