CPower

The State of Demand-Side Energy Management in North America

Volume III

2021-2022

Table of Contents

Click to jump to a section

Volume III

Markets

If Thomas Edison could see the world today...

He'd likely marvel at the evolution of several modernities he helped invent.

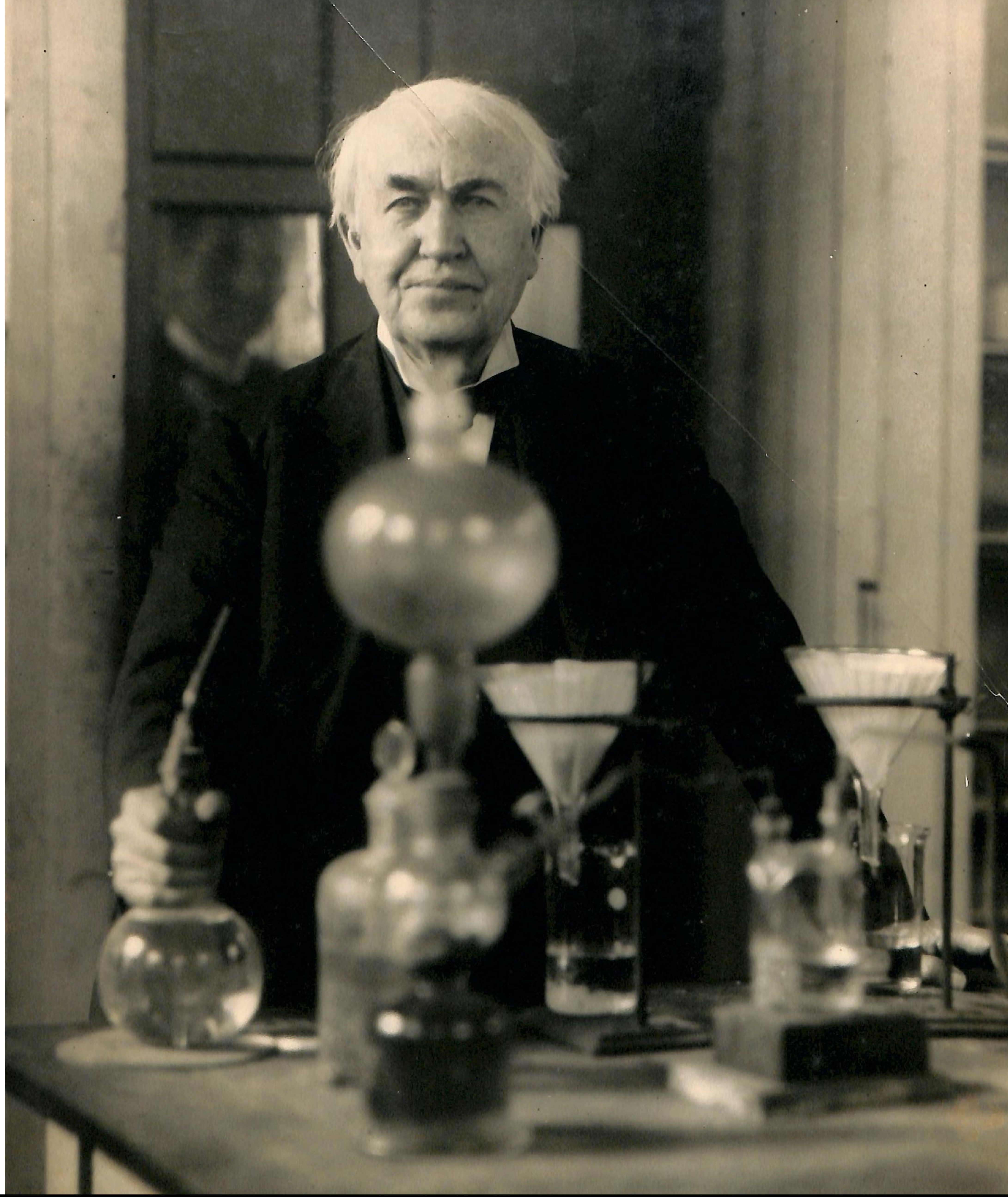
The light bulb's journey from Edison's own incandescent systems that wowed in 1881 at such high-profile public events like the Paris Lighting Exhibition to the energy efficient LED bulbs of today would certainly be worth a day of the great inventor's study and fascination.

Having designed a battery that would be introduced in Henry Ford's iconic Model T in 1912, Edison would no-doubt also be impressed with the present-day ubiquity of electric vehicles. He might be even more astonished with those vehicles' ability to not only plug in and charge their cells at charging stations throughout the country but also their ability to provide capacity back to the electric grid.

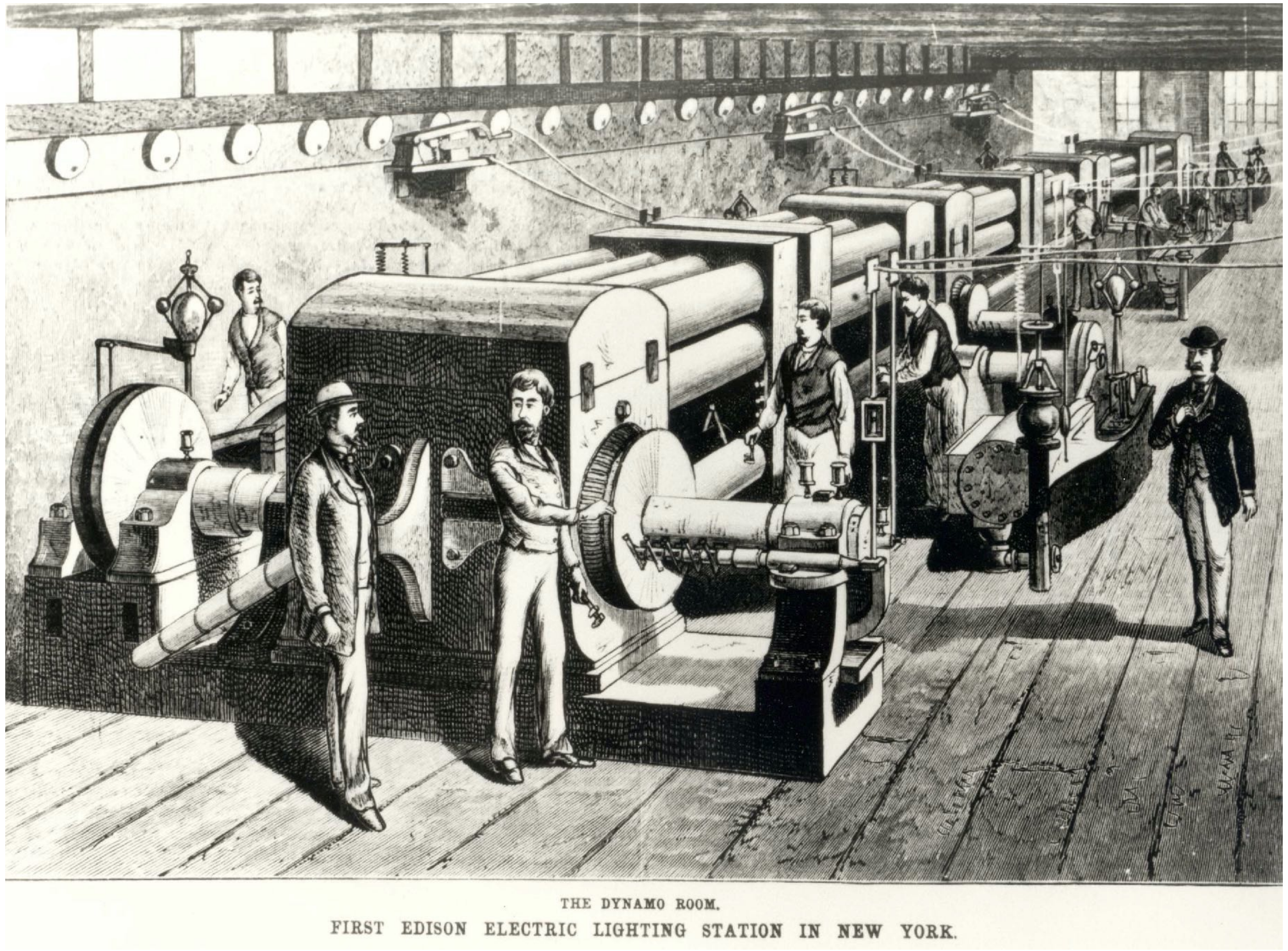
Indeed, the very nature of how electricity flows on today's electric grid would certainly be of interest to Edison. A champion of direct current, Edison thought of electricity for much of his life the way scientists had viewed it for centuries—a continuous flow of current in one direction.

But what would Thomas Edison think of the *bi-directional* electric grid of today, in which electricity flows not from a central point of generation as it had during Edison's time until his death in 1931 and would continue to do throughout much of the 20th century, but from many points of origin to its point of consumption?

To get his head around this modern marvel, Edison would likely conjure fond memories of September 4, 1882, when at 3 PM he turned on the generators at Pearl Street Station in Lower Manhattan, giving birth to America's first electric grid—a distributed grid at that, with generation located at the site of demand.



Source: National Parks Gallery



Pearl Street Station in Lower Manhattan, Source: Public Domain

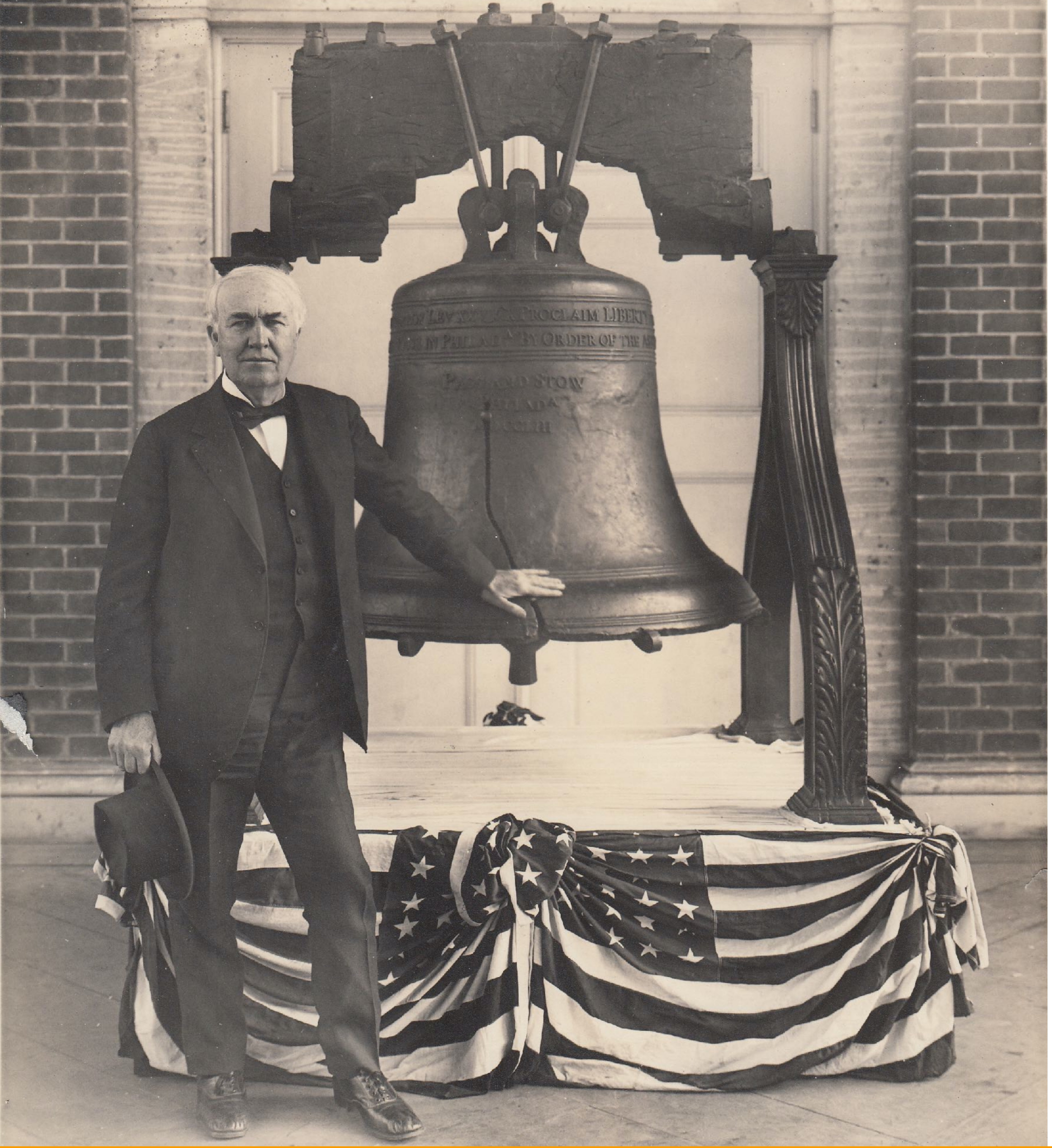
By the time of his death in 1931, Edison's vision of a nationwide electrical grid distributed by direct current had long become a hallucination, replaced by the realities of an ever-expanding grid powered by alternating current, championed by inventor and one-time Edison employee Nikola Tesla and muscled into practice by investor and entrepreneur George Westinghouse.

But it would be another of Edison's former employees, Samuel Insull, who would have perhaps the greatest impact on the grid and the electric industry during the first half of the twentieth century.

A former personal secretary of Edison, Insull would develop and profit from his own creation of the regulated monopoly, which he made central to his hotly contested but ultimately successful argument for America's electricity infrastructure in the 1920s. Widely credited as the inventor of such business model staples as time-of-use electricity rates, Samuel Insull would go down in history as the father of the modern electric utility.

Imagine Edison in 2021, emerging ninety years after his death to view the grid of today and examine its evolution and that of the industry built around it.

He'd certainly study electricity's flow not just from a central plant to its point of consumption as he'd always imagined, but also from points throughout the distribution system from "prosumers," commercial and industrial organizations that both consume and produce electricity to serve the needs of the grid.



Source: National Parks Gallery

Eventually, the great inventor and lifelong entrepreneur might ask many of the questions the team at CPower answers in this, the third volume of our annual *State of the Demand-Side Energy Management in North America.*

Each year we take an in-depth look at the issues and trends affecting the deregulated energy markets in the US and present a breakdown of the key items we think organizations like yours need to understand to make the most of your energy use and spend in the coming year.

If Thomas Edison could see the grid of today, he'd likely be amazed that the opportunity to earn money by supplying electricity to the grid no longer exists solely among the few centralized plants and utilities and operators that control them.

He'd be awestruck at the opportunities available for commercial and industrial organizations to use their existing energy assets to earn revenue by helping the grid stay in balance. He'd surely also be inspired by the ways organizations across the country are using demand-side energy management to reduce carbon emissions and achieve their sustainability goals.

So are we.

It's a big electric grid, a bigger country, and it's an exciting time to be traveling across the bridge to energy's future.

Let's go.

Source: Oregon Department of Transportation

Source: Mark Thompson

President H.W. Bush signs the Energy Policy Act of 1992, which assists the implementation of the National Energy Strategy and helped to pave the way for energy deregulation within the United States. Source: Energy.gov

A Brief History of Demand-Side Energy Management

by Kenneth Schisler, Vice President of Regulatory Affairs, CPower

As you read these words, know that we are currently in the third generation of how demand-side resources participate in the grid.

The first generation began around the turn of the 21st century, an innovative time in energy's history when demand-side load was used to respond to grid emergencies. This was demand response, essentially in its infancy, with loads from commercial consumers who had arrangements to reduce power when they received instructions from grid operators in times of need.

The second generation of demand response, or DR 2.0, began around 2010 when renewable resources like wind and solar started to become more prevalent and grid operators were first starting using loads to help balance the grid in times of intermittency when the sun stopped shining or the wind ceased to blow, causing solar and wind resources to stop generating electricity.

The answer to intermittency was *fast-starting* resources that could come online and provide the grid with flexibility to handle the steep demand ramp that can occur on a daily basis, as anyone familiar with the California Duck Curve understands.

The third generation is where we are today and is the most exciting from a resource and opportunity standpoint. That's because this third generation involves distributed energy resources, including electric vehicles and batteries that are being utilized at customer sites for resiliency and sustainability in addition to the financial gains they offer.

This third generation also involves aggregating different types of distributed energy resources. For example, the activities of solar generation, demand response, and batteries located at the same or different locations working in unison to deliver grid services can be combined into one unit as though they were one resource. This aggregated portfolio is able to deliver more value than it could were the resources to operate independently.

The resources that comprise DER 3.0 can also inject energy back to the grid or store it. As this flexibility increases, so too does decarbonization, making the grid of today much cleaner than what we've known in the past.

All of this evolution points to the grid becoming even greener, more efficient, yet more complex in the future. With this complexity, however, comes the opportunity for commercial and industrial organizations to help the grid and earn a lucrative financial reward in return.

How the "3 D's" and "Prosumers" are Helping the Grid Evolve

by Mathew Sachs, Senior Vice President | Strategic Planning and Business Development, CPower

There are three macro trends that have made headlines in the energy industry over the last few years concerning the grid's evolution. We call them the three D's: **decarbonization, digitization, and decentralization.**

Most who read this book will likely be familiar with the three D's, but let's offer a few quick definitions for those who aren't.

The three D's each refer to the dominant characteristics that will define the grid of the future. Unlike the grid that dominated the 20th century, the grid of tomorrow will be cleaner (decarbonized), technology-driven (digitized), and will incorporate more sources of distributed generation at multiple points on the distribution grid (decentralized) to complement centralized generation on the transmission grid.

While the three D's are ultimately viewed as desirable for the grid of the future, they're creating challenges for grid operators and distribution grid operators (utilities) in the present.

As solar and wind resources have become less expensive, they've been increasingly integrated into the grid to make for a cleaner generation mix, albeit one that creates intermittent generation and poses reliability concerns. At the same time, fleets of electric vehicles plugged into the grid have created an unclear demand profile. These challenges add to another the grid has faced for some time, namely an underutilized generation and transmission infrastructure, meaning that some generation (and associated parts of transmission grid) are only used on the peak hours and/or days of the year.

In short, we have a supply dominated network right now. During this time of transition, the grid needs flexibility. By flexibility, we mean the ability to provide power and increasingly quick turnaround at any time of the day or year and for changing durations as well as more frequent calls or dispatches. Organizations that can provide this flexibility are helping the grid and should be financially rewarded for that help.

This is where we should focus on the grid's decentralization.

Today, the grid is in the midst of a transition to an omni-directional framework whereby demand reacts to supply, essentially a reverse of the centrally oriented grid of the 20th century.

Over time, this omni-directional framework will develop with consumers injecting electrons into the network. At this point, consumers of electricity become prosumers, meaning they are consumers who use electricity but also provide services to the grid.

Ivanpah Solar Electric Generating System (ISEGS) Source: USFWS Pacific Southwest Region

Examples of prosumers today are customers who participate in demand response. Prosumers also include consumers who use their behind-the-meter generation or an energy storage capability to participate in a program with their local utility or with the organized wholesale market.

Over the last several years, there has been a wave of technological innovation that has made these energy resources practical and affordable and, in turn, has allowed prosumers to become viable players in helping the grid evolve along the trajectory outlined by the three D's.

Last fall, the Federal Energy Regulatory Commission (FERC) issued an important Order that's going to modernize regulations to make it easier for distributed energy resources to benefit from participating in wholesale markets.

Order 2222 has been called a landmark, a game-changer, and plenty of other praising names normally reserved for an historic moment. In time, it may prove to be all of those and more.

Let's spend a few moments in the next article understanding what it is and, more importantly, what it means for the evolving electrical grid in the US.

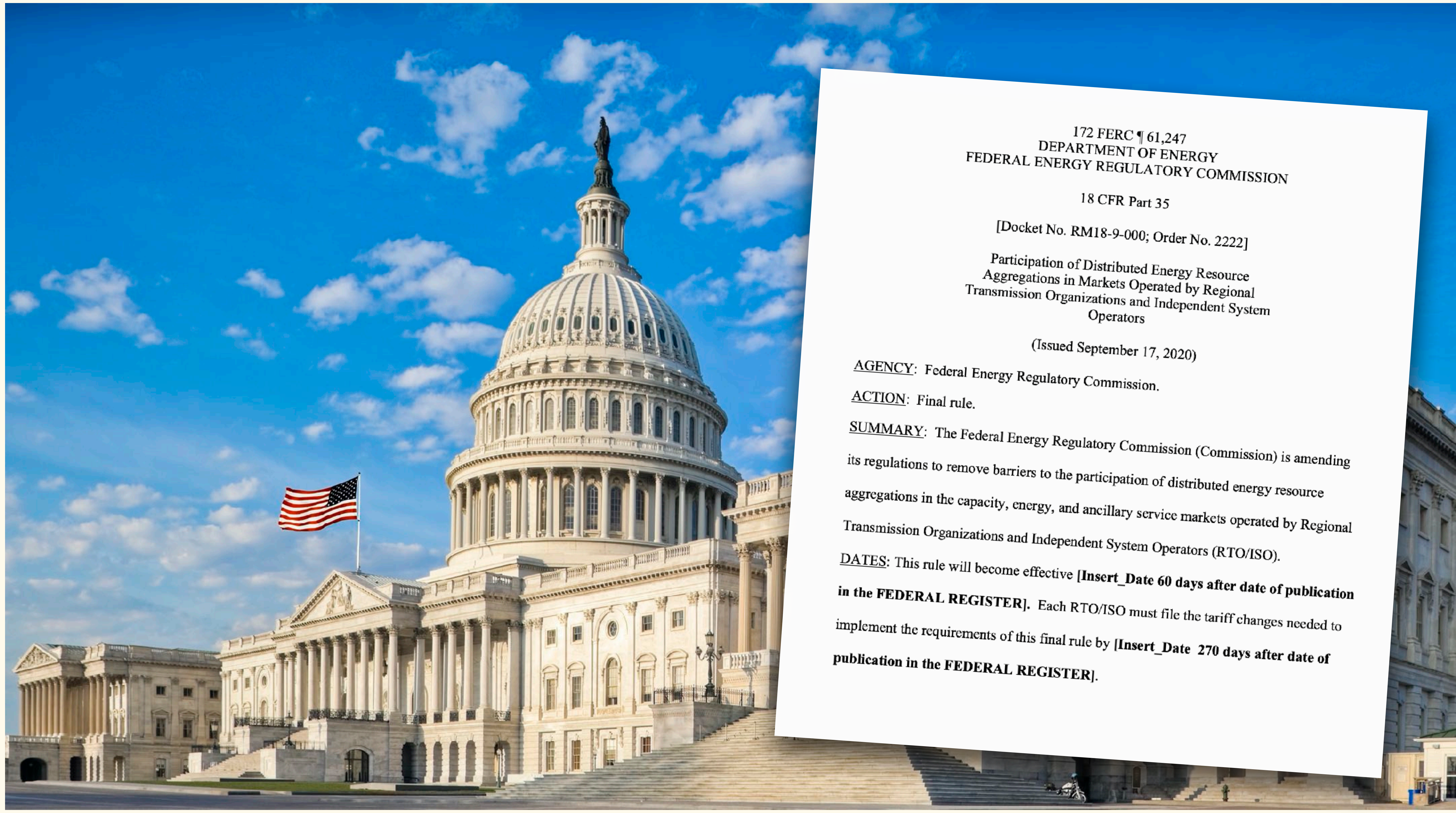
FERC Order 2222:

A Primer for Understanding Crucial Legislation

by Bruce Campbell, Director of Regulatory Affairs, CPower

Since being issued in September 2020, the Federal Energy Regulatory Commission's (FERC) Order 2222 has been heralded as a landmark achievement in the history of the energy industry, one that years from now may be seen as a watershed moment when the grid took a giant leap forward in its evolution.

Before we get overwhelmed by hype and possibility, let's take a minute to examine and clearly explain this order so your organization understands it and can use that knowledge to make an informed, educated decision on your energy use and spend.



When Language Matters, Study the Source

Language is important when it comes to interpreting and understanding energy regulations. Let us then examine FERC's exact words concerning Order 2222 so you understand for yourself what they mean and you don't get caught up or misled by someone else's well-meaning and enthusiastic but perhaps not-entirely-accurate explanation of the order.

The following is verbatim from FERC:

"Order No. 2222 will help usher in the electric grid of the future and promote competition in electric markets by removing the barriers preventing distributed energy resources [DERs] from competing on a level playing field in the organized capacity, energy, and ancillary services markets run by regional grid operators."

Order 2222 Exemplifies FERC's Mission: Regulate Wholesale Power Markets

One of the Federal Energy Regulatory Commission's primary responsibilities is to regulate the sale of electricity in the wholesale power markets, which are composed of the organized capacity, energy, and ancillary services markets that are run by the regional grid operators in the US.

To be clear, Order 2222 involves wholesale power markets, which refer to the buying and selling of power between generators and resellers. In contrast, the transaction that occurs when your organization purchases and consumes electricity takes place in the *retail* power market.

Order 2222 affects the wholesale power markets, NOT the retail markets.

It's FERC's responsibility to ensure that the competition in US wholesale power markets is *just and reasonable.* The markets exist to foster competition and FERC acts as essentially a referee, making sure one entity doesn't have an unfair advantage over another.

In this respect, Order 2222 is right in the wheelhouse of FERC's jurisdiction and mission.

Nonetheless, it is important to understand that the interconnection of DERs with the grid remains subject to local utility interconnection rules that are state jurisdictional and that these rules can encourage or discourage DER activity.

DERs are the Grid's Future…

Order 2222 Paves a Fair Path Forward

Until the last few years, most of the electricity entering the wholesale markets in the US originated from large traditional generation sources–coal, oil, or natural gas, for example–and was offered into the market by entities who controlled those sources, which we'll call traditional electric resources for simplicity's sake in this examination.

Today, however, distributed energy resources–or DERs as they're commonly called–have become increasingly popular and have long-sought to enter the wholesale marketplace and compete alongside traditional sources.

Order 2222, as FERC clearly states, seeks to allow DERs to compete on a fair and level playing field in the wholesale power markets.

Order 2222 Defines Distributed Energy Resources (for everyone)

Let's take a moment and consider how FERC defines distributed energy resources because this is a term that (like many in the energy industry) isn't necessarily uniform in its definition and can mean different things to different people.

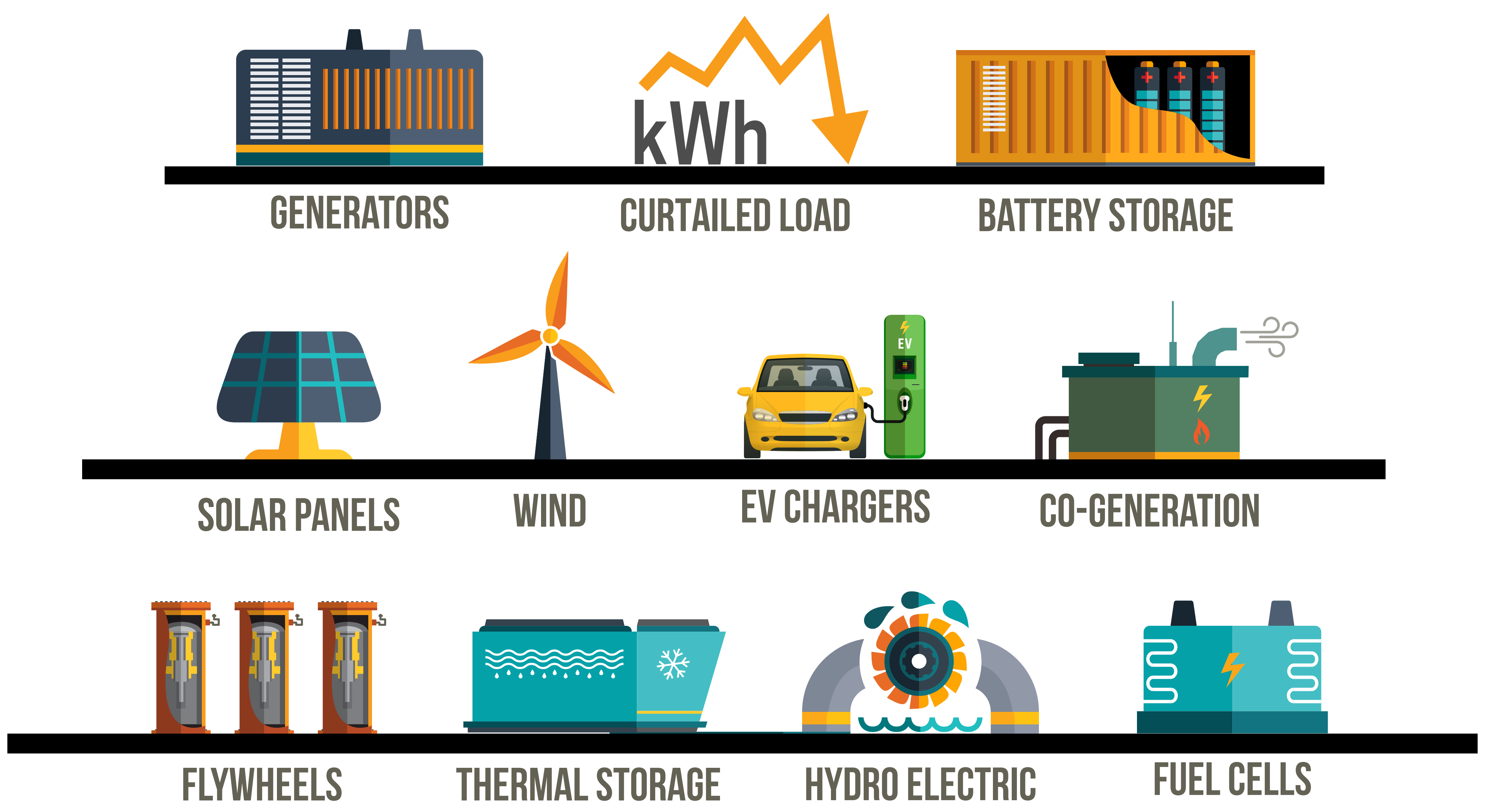
Again this language is verbatim from FERC:

"DERs are small-scale power generation or storage technologies (typically from 1 kW to 10,000 kW) that can provide an alternative to or an enhancement of the traditional electric power system. These can be located on an electric utility's distribution system, a subsystem of the utility's distribution system, or behind a customer meter. They may include electric storage, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage or electric vehicles and their charging equipment."

This text is worth understanding because it formally defines what has previously been nebulous and open to varying interpretations. FERC desires to create a "level playing field."

The "level playing field" that Order 2222 seeks to create means FERC wants to make sure that assets entering the market as distributed energy resources have equal opportunity to compete against those entering the market as traditional electric resources.

If we look at FERC's recent history of orders–including 2011s Order 745 involving demand response resources participating in wholesale markets and 2018s Order 841, concerning the same of storage resources–we find the Commission has been striving to establish this level playing field between traditional market participants and inevitable new players in the marketplace for some time.



What Does Order 2222 Do (specifically) for DERs?

At this point in our examination of Order 2222, we know FERC's objective is to create a playing field that fosters fair competition among market participants.

Let us now take a look at the operative phrase of the order, which instructs regional grid operators to *remove barriers* preventing distributed energy resources (DERs) from competing on this level playing field.

A good question for us to ask now is what are these "barriers" standing in the way of DERs getting a fair shake in the wholesale markets?

The answer is complicated because the six deregulated energy markets in the US have very different rules for participation. It's precisely those rules–or more to the point, tariffs—that Order 2222 instructs grid operators to revise, so that–again, in FERC's words—distributed energy resources are established "as a category of market participant."

Learn more: Distributed Generation

When will we see results from Order 2222?

Back to the horse's mouth and FERC's wording: "Order No. 2222 takes effect 60 days after publication in the Federal Register. Grid operators must make compliance filings to FERC within 270 days of publication in the Federal Register."

Here, we see that at the absolute earliest, the intentions of Order 2222 won't be fully realized in the marketplace for nearly a year.

If the saga of FERC Order 841 is any indication, it will be some time before grid operators fully comply with Order 2222 and make the necessary adjustments to the tariffs that affect their markets and allow DERs the same access traditional assets have enjoyed.

It's not unreasonable then to expect grid operators to submit appeals, file extensions (MISO, PJM, SPP, and ISO-NE have already asked for and received extensions), and otherwise take longer than 330+ days to adhere in full to FERC's order.

On to the Future...

Order 2222 is important because it not only acknowledges the long-held conviction that DERs will play an integral role in the grid of the future, it also guarantees that in the very near future distributed energy resources such as rooftop and community solar, backup generators, fuel cells, demand response, energy storage, microgrids, and energy efficiency will take their place at the adult table in the country's wholesale power markets.

For now, there are many ways to monetize DERs in US energy markets, especially with demand response, which pays organizations to use less energy when the grid is stressed due to lack of reliability or high electricity prices. Expect those opportunities to increase as Order 2222 is implemented.

Source: Walmart

Source: FirstEnergy Corp

The Debate Over the Demand Response Opt-Out Rule

by Kenneth Schisler, Vice President of Regulatory Affairs, CPower

In March 2021, FERC announced its intention to review the demand response "Opt-Out" rule, a 2008 Order which granted states the final say on whether aggregators of retail electricity customers can participate in RTO/ISO demand response programs.

The debate over the DR opt-out lands squarely in the arena of the conflict between states and the federal government that is happening in both PJM and New England. The rule in question explicitly gives each state a veto over the application of a federal rule.

Normally, this is not how the US federal system works, which is why we feel it's worth examining the context under which the rule was originally passed so we can 1) illustrate just how much multi-state energy markets like PJM and ISO-NE have evolved over the last 12 years and 2) explain why we feel that the opt-out rule is detrimental to the continued evolution of the grid toward a cleaner and more efficient future.

The History of the Opt-Out Rule

The opt-out rule was approved in 2008, at a time when the competitive wholesale RTO/ISO markets in the US were less than a decade old.

Many states at that time—including California and several eastern states— had already made a transition to retail competition and were successfully using dispatchable demand response in their wholesale markets as a way to balance their grids and reward their participants.

Some states—particularly those in the Mid-continent Independent System Operator (MISO) and Southwest Power Pool (SPP) markets—were then dominated by markets that had NOT yet become open to retail competition and were traditionally regulated at the state level.

FERC then introduced the opt-out rule as essentially an olive branch to the states who, in 2008, may have been concerned that their state jurisdictions were in danger of being usurped by a federal body who might be pushing them toward adopting retail competition policies.

FERC adopted the opt out rule under three assumptions that seemed logical at the time.

First, the Commission assumed states would support DR if given the option to refuse participation in the event they felt it interfered with their state retail policies.

Then, FERC assumed that states would come to see the benefits of allowing wholesale market DR as a means to reward retail customers for helping the grid in times of need.

Lastly, FERC assumed that if their first two assumptions proved true that states would seldom use the opt-rule, or perhaps they would not use it at all.

All three of FERC's assumptions did not prove to be correct. With the third assumption, FERC made an egregious miscalculation. Skeptical of having retail deregulation forced down their legislative throats, non-restructured states utilized the opt-out rule en-masse, essentially employing FERC's olive branch as a barrier to keep their retail jurisdiction wholly intact.

Why the Opt-Out Rule Should Go (and Why That's Good for States, the Market, and the Grid)

Eliminating the DR opt-out rule will NOT infringe on rights the states currently possess.

States currently enjoy complete jurisdiction over resource adequacy. Moreover, states are wholly authorized to ensure that the resource mix in their states meets the specific needs of their desired energy future.

Eliminating the DR opt-out rule will, however, help states achieve the very energy futures they seek. By incorporating ISO/RTO demand response into their resource planning, states can afford to increase their generation mixes to include more wind and solar sources.

With demand response and other flexible demand-side resources available to shore up the grid when wind and solar's inherent intermittency threatens reliability, states can take much more significant strides to the cleaner fuel mixes and futures they desire than they could while clutching to the antiquated opt-out rule as an unnecessary security blanket.

As FERC moves forward to improve regulation of DR and distributed energy resources under its jurisdiction, states can seize the opportunity to develop retail policies that unleash the potential on the demand side in both the retail and wholesale markets to increase reliability and efficiency, reduce costs to serve, and foster innovation.

What the Electric Grid's Future and the Internet's Past Have in Common

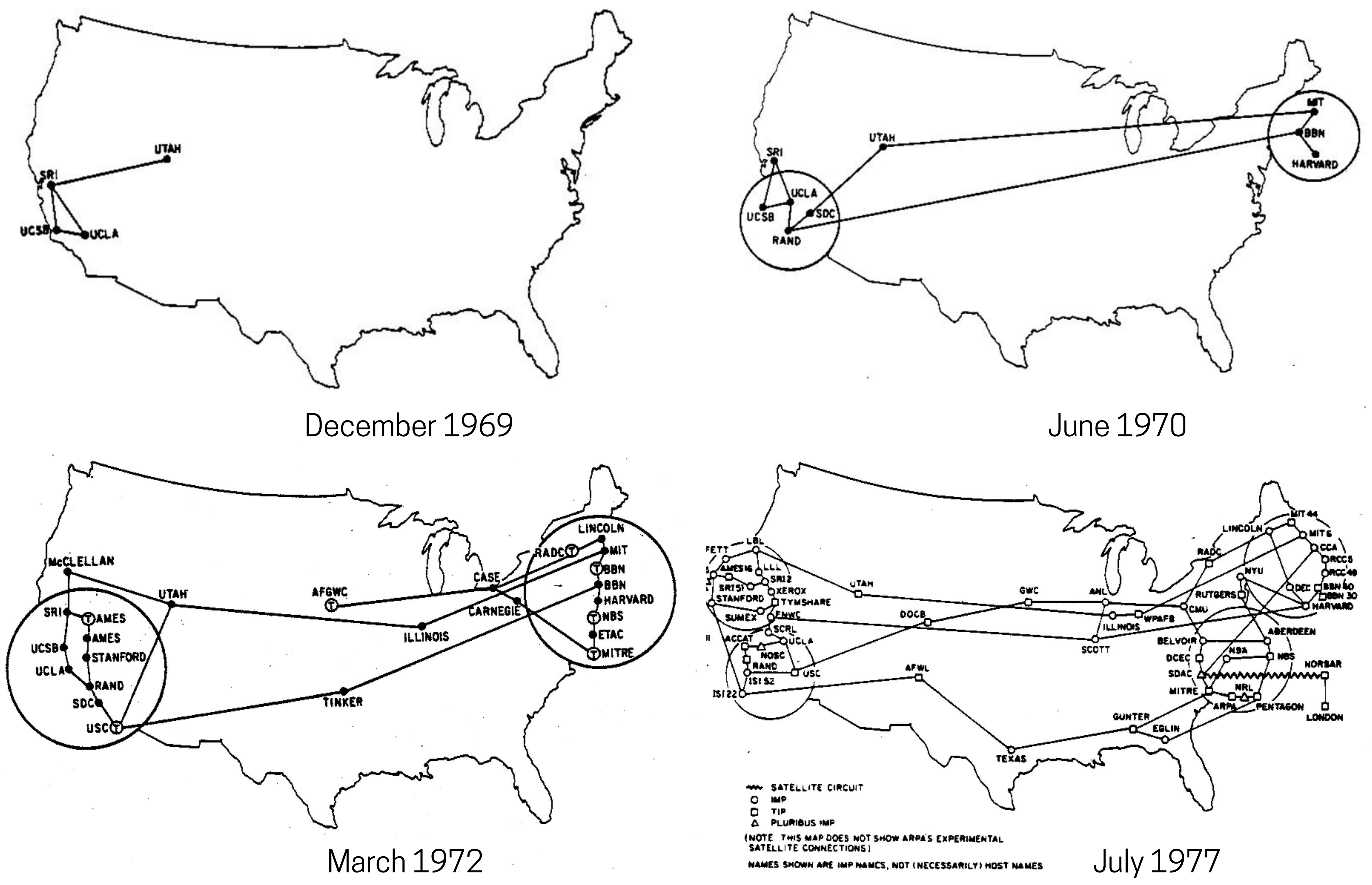
by Mathew Sachs, Senior Vice President | Strategic Planning and Business Development, CPower

In the mid 1960s, a new method for effectively transmitting electronic data over a computer network was born, and with it came one of the quintessential building blocks of what would become the modern internet.

In simple terms, "packet switching" is a routing method whereby data transmitted across a network takes different routes along the network to arrive at its destination. Packet switching allowed for computer networks to become decentralized, ultimately giving rise to the internet and the global connectivity it provides today.

Just as packet switching would help computer networking explode into the future, so too will a similar decentralization usher the electric grid from what it was for the previous century to a more efficient interaction that connects consumers in a cleaner and more collectively-beneficial way.

Like most revolutionary ideas, packet switching was not embraced by the established community of experts that presided over the nascent field of computer networking in 1965. That changed, however, when the Advanced Research Projects Agency Network (ARPANET) embraced packet switching as a means to allow multiple computers to communicate on a single network.



The Evolution of ARPANET. Source: Public Domain

Originally funded by the US Department of Defense and widely considered among historians as the first working prototype of the internet, ARPANET would adopt the internet protocol suite TCP/IP on New Year's Day in 1983, and begin assembling the network that would become the modern internet.

SInce its inception, the grid has grown and evolved to become a modern network on the cusp of transitioning to a more efficient future. To get there, the electric grid may borrow a page from the information superhighway and follow a few key transformational lessons.

Consider how information travels on the internet in 2021.

On the internet, every user is a consumer, producer, and storer of information. Send an email from the Northeast US today, and it might route through Canada on its way to a final destination. Send an email to the same person tomorrow, and it might take an entirely different path through a server in New York.

In essence, this is packet switching on steroids.

The pathways that allow for information to travel on the internet are *omni-directional*, which has allowed that network to rapidly grow over the last two decades to serve billions of users worldwide.

That was not always the case if you consider how, prior to packet switching, the original computer networks were constructed as a network dominated by central mainframe servers that *pushed* information and data to users connected at terminal locations.

BBN ARPANET Group. Source: Public Domain

The electric grid has a similar history to the internet's in that the grid's network was centralized from the outset, with large generation sources (power plants) essentially pushing electricity to consumers via transmission and distribution.

The centralized grid conceived by the likes of Thomas Edison and erected by moguls like George Westinghouse served its users well for the better part of the century.

Like the internet, however, the electric grid has evolved to embrace decentralization as it transitions to an omni-directional network in which generation and distribution are spurred by the very users for whom the grid exists to serve.

Today, for example, the electricity you use to charge, say, your mobile phone may come from the bulk grid. Tomorrow it could come from another consumer on your distribution grid who is not using their own excess generation.

As grid operators and utilities adopt new technologies to enhance their flexibility and optimize the delivery of electricity, the grid will start to follow a similar path the internet embraced in its evolution to the modern wonder it is today. The result will be an energy system whose connectivity drives its efficiency and sustainability for decades to come.

It's an exciting time for the grid and its users, rife with possibility and opportunity.

US Electric Utilities and the Grid of the Future

Guest Contribution by Paul Wassink , Senior Engineer | National Grid

Photo: Rod Waddington

An inherent flaw in any electrical grid lies in the inevitable truth that the entire grid system—from the generators to the transmission lines to the substations to the power lines and transformers outside of homes and businesses—must be sized to serve peak use.

For many grids in the US, peak energy use happens over just a few hours on hot summer days. In Massachusetts, for example, it has been estimated that the top 10% of high load hours during the year account for about 40% of the cost of operating the grid [1]. Shaving electric use during these key hours of high usage can therefore have a significant benefit in reducing long-term electric rates.

The goal of utility demand response programs is to strategically reduce energy use at those peak times which, in turn, keeps overall costs (and rates) down by reducing the need for expensive and dirty peaker plants while also reducing the required size of grid infrastructure.

Demand response and traditional energy efficiency are fast becoming a viable tool through which utilities across the US plan to reduce peak usage and realize those savings for our customers.

[1] State of Charge, Massachusetts Energy Storage Initiative, page i.

The Road to Tomorrow: Possibilities and Challenges

There is still some debate over what the best path to the future may be and how quickly we can get there, but the end goal for many US electric utilities is clear. To address climate change and other environmental and equity issues, we need an environmentally sustainable power system.

For the Northeast, as for much of the country, this will mean integrating into our grids a lot more solar and wind power to complement existing hydro resources and hopefully (for those of us in the US Northeast) access to even more hydro resources from our Canadian friends.

Solar and wind are valuable and popular resources that should be encouraged during the grid's transition from the way it was structured and operated for most of the 20th century to a tomorrow lush with sustainable possibilities.

As has been well documented, however, the sun is not always shining, and the wind is not always blowing. For the grid to overcome the inherent intermittency of these clean renewable energy sources and evolve to a cleaner more efficient future, demand response will play a crucial role in balancing the use of electricity with its supply.

Block Island Wind Farm, Rhode Island

The Increasingly Important Role of Demand Response

Today, many demand response programs at the utility level are simple in design, yet effective in achieving results. Most utilities execute their DR programs on peak days in order to reduce peak usage. To attain the future we all desire, however, utilities will need to add new demand response programs to help balance the grid every day of the year.

Battery storage will also play a critical role in this transition to the future. At National Grid in the Northeast US, for example, battery storage is already an important part of the suite of demand response programs we use to manage peak usage on our electric grid.

Relying on storage alone to solve every peak issue, however, would be more expensive than if we were to also include other types of tried-and-true demand response strategies such as turning down HVAC, lighting, or process equipment, and using CHP units and generators during times of demand response participation.

This challenge will be best solved with each utility offering a diverse portfolio of DERs including demand response to serve the needs of its evolving grid.

6-MW/48-MWh battery storage system unveiled on Nantucket Island in Massachusetts

Creating a More Cost-Effective Grid at the Utility Level

Much has been made about the benefits to all customers for addressing climate change and other environmental problems. What hasn't been shouted from the rooftops is the very real possibility that the grid of the future will also be cheaper and more equitable than what we've known in recent decades.

The cost of solar, wind, and batteries has dropped considerably in the last five years. These once cost-prohibitive resources are now among the cheapest resources available and have been seized upon by suppliers on the supply side of electricity's exchange and consumers on the demand side.

Now more than ever, electric utilities across the US need demand response programs to better integrate these key resources into the grid so everyone can benefit from the reduced costs and lowered emissions they enable.

National Grid, like many utilities across the US in deregulated energy markets, is not allowed to own or operate power plants per regulations at various federal and state levels. The regulations that govern us and other utilities involve revenue decoupling mechanisms that ensure our utility's profits are not tied to increasing electricity sales. Instead, our regulators have put other performance-based incentives in place for us to make sure that our interests always align with our customers' interests.

Demand response and the rest of our energy efficiency portfolio is a great example of these incentives. As the saying goes, the most valuable kilowatt of electricity is the one you do NOT use. For decades, we and other utilities across the country have offered energy efficiency programs to our customers, because it is a lot cheaper to save energy than it is to build new power plants and grid infrastructure.

About the author:

Paul Wassink is a senior engineer at National Grid, an electric and natural gas utility in the Northeast US and UK. Paul has been running the National Grid demand response programs in Massachusetts and Rhode Island since they were introduced more than 5 years ago.

Financial Incentives as a Driver of Change

How do we get that to a lofty goal of having 100% of our electricity generated from renewables? It's a complex answer which requires efforts on both the supply and demand sides.

The opportunities for both commercial and residential consumers to serve their clean and renewable loads back to the grid will likely thrive if the right incentives are in place.

For starters, utilities will need to introduce incentives to encourage more households and businesses to install behind-the-meter solar and storage while simultaneously incentivizing the acceleration of front-of-the-meter solar and wind farms.

That being said, there is a lot more that electric utilities need to do to get the word out to our customers about existing incentives to adopt renewables. Many customers would likely move on this today, if they knew how lucrative renewables can be and how much they help the environment.

Of course, the grid needs to be ready to accept all that new renewable generation. The challenge then for utilities is to develop customer-friendly programs that incentivize customers if they allow their utility to discharge and charge their batteries at the right times and tweak their inverter settings to improve power quality.

Utilities will also need to further develop the system used to manage distributed energy resources so that the right signals are sent at the right time to the right places on the grid in order to unlock the maximum benefit and reduce emissions and overall costs.

It's an exciting time for electric utilities. The grid is evolving and we, along with our customers, are evolving with it, poised to do our part to help keep the power flowing, rates affordable, and the Earth plentiful during this important transition to energy's sustainable future.

Achieving Carbon Emission Goals with Demand-Side Energy Management

by Mathew Sachs, Senior Vice President | Strategic Planning and Business Development, CPower

A convergence of pressures in recent years has caused organizations across North America to examine how their energy use can be managed to help achieve their carbon reduction goals.

These converging pressures originate from customers, who desire to do business with sustainability-minded companies; investors, who realize the inherent value associated with an organization being carbon neutral; and regulators, who are introducing laws that reflect and address society's move toward a cleaner energy future.

Since these pressures show no signs of waning, the question of how exactly demand-side energy management can be optimized to achieve carbon goals is becoming a popular discussion in the industry today.

Some of the best practices for carbon-reducing with demand-side energy management are more obvious than others. Adopting energy efficiency measures or installing on-site renewable energy sources like solar are examples of strategies that have been around for decades.

Let's examine, then, some of the newer concepts on the topic of achieving carbon goals with demand-side tactics.

Consider the drive toward a carbon-neutral future from the grid operator's perspective. Across the US, grids face the same converging pressures as organizations and have worked to increasingly shift their generation mixes away from fossil fuels and toward renewable sources like wind and solar.

Of course, wind and solar energy sources are inherently intermittent and can subsequently cease generating if the wind stops blowing or the sun stops shining.

But the immutable truth that some days are overcast and others windless doesn't ease the pressure on the grid and those who run it to drive toward carbon-neutrality! Nor does inescapable intermittency suffice as an acceptable reason for grid operators to sacrifice reliability in the name of sustainability.

So what's a grid operator to do?

Here is where commercial and industrial organizations can fill the gap from the demand side and help the US electrical grid find its way to the clean and efficient energy future that everyone desires.

That the grid needs flexible resources which can be dispatched quickly to serve load when it's needed due to wind and solar generation being unavailable is a central point readers of this book should be quite familiar with, given it's been examined in detail within these pages over the last three years.

The same is true of the role demand response plays in providing that flexibility to the grid.

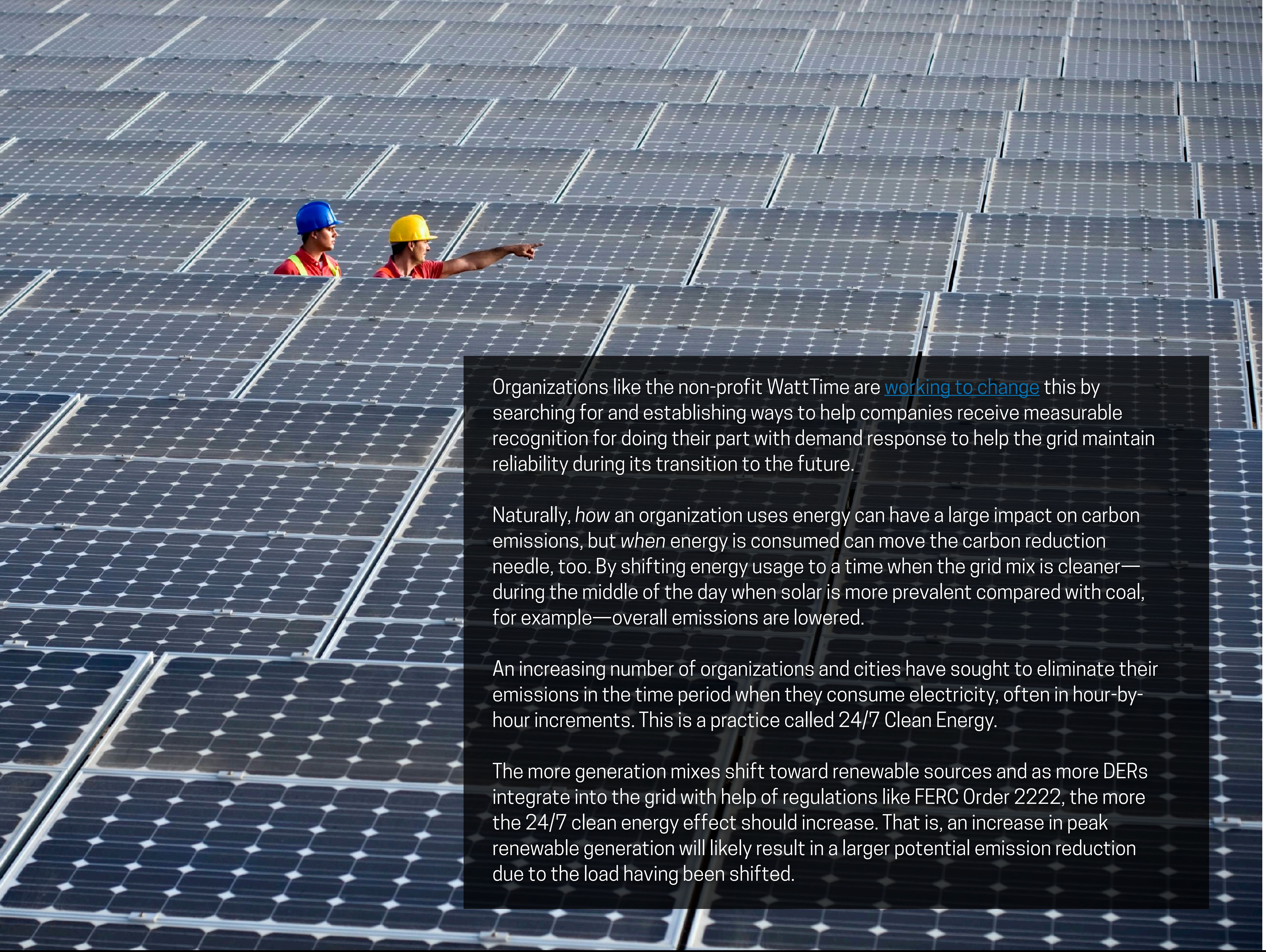
What’s becoming more apparent is how increased participation in demand response programs at the ISO and utility levels across the US is providing new tools for grid operators to harmonize their grids’ reliability with their drive toward a future of cleaner generation fuel mixes.

In effect, this demand-side participation enables the firming of renewable energy sources, allowing grids to transition toward cleaner fuel mixes. While demand response participation doesn’t directly help individual organizations achieve their own carbon reduction goals, the cumulative effect of all the organizations’ participation does help our society achieve its desired emission goals.

The pressures organizations face from outside entities that we discussed earlier play a role in driving a given company’s carbon-reduction goals.

Unfortunately, in a reward-based world dominated by measurable metrics, there isn’t a practical way to note just how effective a given organization’s demand response participation is in helping contribute to carbon and greenhouse gas reduction.

That’s starting to change.



Organizations like the non-profit WattTime are [working to change](#) this by searching for and establishing ways to help companies receive measurable recognition for doing their part with demand response to help the grid maintain reliability during its transition to the future.

Naturally, *how* an organization uses energy can have a large impact on carbon emissions, but *when* energy is consumed can move the carbon reduction needle, too. By shifting energy usage to a time when the grid mix is cleaner—during the middle of the day when solar is more prevalent compared with coal, for example—overall emissions are lowered.

An increasing number of organizations and cities have sought to eliminate their emissions in the time period when they consume electricity, often in hour-by-hour increments. This is a practice called 24/7 Clean Energy.

The more generation mixes shift toward renewable sources and as more DERs integrate into the grid with help of regulations like FERC Order 2222, the more the 24/7 clean energy effect should increase. That is, an increase in peak renewable generation will likely result in a larger potential emission reduction due to the load having been shifted.

Companies, regulators, and markets are in the early stages of ascribing a value to 24/7 clean energy practices.

Consider the New York market, where Local Law 97 (LL97) seeks to reduce carbon emissions in the city's building stock by 80% by 2050. An estimated 50,000 buildings in New York City stand to be affected by the law, with many in the commercial sector currently above the law's emission requirements. Retrofits are one means of achieving compliance with LL97. Load shifting may be another, albeit one that will require a tangible means of assigning value to the practice.

Here we have an example of a regulation (LL97) creating a need for a possible market incentive (the value assigned to load shifting) as a means to achieve the societal goal of lowering carbon emissions in a densely populated city.

Absent a concrete policy on climate change at the national level, the market is responding. Throughout each of the deregulated energy markets in the US, demand response programs are growing at the ISO and utility level. The markets are becoming more sophisticated with how they incorporate DERs, and they're doing all of this at the behest of state legislatures as well as the citizens who the market and grid ultimately serves.

Demand-side resources deliver carbon benefits. They always have, but today more opportunities are emerging to earn revenue with these resources.

For years we've touted how flexible resources will help drive the US electric grid to a cleaner future. While the ways organizations that provide those resources will be publicly credited are still undecided, they ways they'll be financially rewarded are apparent.

Demand Response Has Been Part of America's Energy Plan for 40 Years.

Why Should the Next 40 be any Different?

by Mathew Sachs, Senior Vice President | Strategic Planning and Business Development, CPower

The idea that reducing a watt of energy on the demand side can be just as valuable as generating one on the supply side in a time of grid stress is hardly new. Nor is the idea that such a solution helps thwart both energy-related and environmental crises.

The origin of demand response can be traced to roughly forty years ago when both the US and the world grappled with many of the same energy and environmental issues we are still trying to solve today.

Let's take a trip back to the mid-late 1970s and see if a few things don't look and sound familiar.

The oil crisis of 1973 sent shockwaves throughout the world, raising concerns on the security of electricity supply in the US while pointing to a need to diversify the nation's power generation mix away from a fossil fuel dependency and toward a mix with a greater share of renewable and clean energy sources.

Global environmental awareness had grown to a movement large enough to be seized upon by newly-elected American president Jimmy Carter who, within a month of taking office, donned a cardigan sweater, sat before a roaring White House fire, and urged Americans to join him in conserving energy in a nationally televised fireside chat.

During that broadcast on February 2, 1977, the president related how a particularly harsh winter had depleted the domestic supply of natural gas and fuel oil. He warned of dark consequences that awaited the most powerful country on Earth if we as a nation failed to devise a sound energy plan for the future.

Sound familiar?

The 39th POTUS didn't outright cite demand response as a means to a profitable and sustainable end that night in 1977, but he did allude to the Public Utility Regulatory Policies Act (PURPA), a piece of legislation that would be enacted in 1978 to promote more competitive energy markets in the US by allowing "non-utility generators" to participate in them.

The act would prove to be a landmark piece of legislation, setting the country on the road to conservation and the development of clean and renewable energy sources. It would also open the door to demand response as a viable solution to keeping both the electric grid and the environment in balance.

That open door paved the way for the deregulated, competitive energy markets we have today to replace the vertically-dominated regulatory ones that had existed for most of the 20th century. It also would prove to be the seed that would soon mature and bear the lucrative fruit of modern demand response.

Watch President Jimmy Carter's 1977 Report to the Nation on Energy

Fast forward back to the present. Federal legislation is still working to ensure energy markets remain competitive with clean and renewable energy sources securing a just and reasonable position in them.

Order 2222 from the Federal Energy Regulatory Commission (FERC) is a case-in-point. The Order is the latest in a series of directives aimed to create a fair balance between traditional generators on the supply-side and distributed energy resources seeking to enter markets on the demand side.

Issued in September 2020, Order 2222 calls for the removal of “barriers preventing distributed energy resources (DERs) from competing on a level playing field in the organized capacity, energy, and ancillary services markets run by regional grid operators.”

Order 2222, widely hailed as a landmark achievement in the history of the energy industry, is about more than just creating more competitive markets. By allowing DERs, including demand response, their just seat in the marketplace, Order 2222 enables the US electric grid to take a giant leap toward a cleaner future.

Source: Nan Palmero

Consider this recent data on demand response performance in the US:

In 2019, the most recent year for which the data is available, the combined wholesale demand response capacity of all regional system operators in the US grew to 27,000 MW.

How much environmental pollution did all that demand response save the country in 2019 by providing a resource that would have otherwise been supplied by a traditional "peaker" plant?

According to the EPA, the 27,000 MW of capacity from all commercial DR participation in the US in 2019 prevented the greenhouse gas emission equivalent of what an average passenger vehicle would produce were it to drive a little more than 142 million miles

That same total of reduced load roughly converts to the carbon dioxide emission equivalent of 63 *million* pounds of coal being burned.

In 2020, CPower's more than 1,700 customers contributed more than 4,000 MWs of capacity to demand response, effectively reducing the energy equivalent of 7 million pounds of coal that would otherwise have been burned and released into the environment.

Helping the grid stay balanced and keeping the air clean aren't the only benefits to demand response.

The global demand response market is projected to value at USD $24.7 billion by 2022, an increase from the $5.7 billion valuation of the same market in 2014, according to a recent report published by Million Insights market research firm.

Photo: John Englart

Much has been made in this publication and others in the energy industry about the evolving electric grid and demand response's role in helping to bridge past, present, and future.

As you read these words, energy markets and electric utilities across America are refining their demand response programs and introducing new ones, providing organizations with a lucrative and socially responsible way to use their energy assets to support grid reliability in this critical time of transition.

America opened the door for demand response nearly forty years ago. Closing it now (even just a little bit) would be a step toward the past in a time when the country should be crossing the bridge to energy's future.

THE STATE OF DEMAND-SIDE ENERGY MANAGEMENT IN

California

Governor Gavin Newsom wanted answers.

It was August 17, 2020, and California was just two days removed from enduring the state's first rolling blackouts in nearly 20 years.

In a letter to the California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC), Governor Newsom demanded to know the exact reasons why millions of Golden State ratepayers were forced to go without power and what could have been done to avoid the crisis.

Nearly two months later, executives from each of the organizations that form California's energy triumvirate formally responded to Governor Newsom. The ensuing report, "Preliminary Root Cause Analysis [of the] Mid-August Heat Storm" cited three causes for the grid's failure.

1. The climate change-induced extreme heat storm across the Western United States resulted in the demand for electricity exceeding the existing electricity resource planning targets. The existing resource planning processes are not designed to fully address an extreme heat storm like the one experienced in mid-August.

2. In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.

3. Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

The day of the report's publication, the Los Angeles Times ran an article whose headline read, "What caused California's rolling blackouts? Climate change and poor planning," capturing the essence of the self-critical evaluation the Governor had received that same day in the Root Cause Analysis.

The article informed the public with an overview of what had been admitted to Governor Newsom in detail. CAISO, the CPUC, and CEC admitted fault and took responsibility for what they called an "extraordinary event," but one that was expected to happen again and therefore needed to be planned for in the future.

In their eyes, and in those of many Californians, climate change will continue to have an effect on the grid and life in California unless mitigation measures are enacted. The report proposed resource planning, procurement, and market practices be explored with the goal of ensuring that "California's transition to a reliable, clean, and affordable energy system is sustained and accelerated."

Some California residents, like former PUC president Loretta Lynch, fear the analysis submitted to the Governor failed to tell the whole story of the breakdown and that the state's ratepayers are at the risk of being victimized by energy markets that are poorly designed.

CAISO disagrees and has stated its markets are functioning as they were designed. If the Root Cause Analysis is to be believed, however, market planning is one the mitigating measures CAISO must explore to ensure safe, reliable, and affordable power is delivered to the state's ratepayers.

That begs a question the energy players in California take seriously: Is it time to revise California's energy markets to shore up the grid's reliability during this time of transition? ◻

The Impact of the August Heatwaves on CA's Grid

The sweltering temperatures that raged across thirteen western states from August 14-17, 2020, had a significant impact on the tens of millions of people who experienced record high temperatures well above 100°F.

The triple-digit temperatures had an historic effect on California's electric grid, too. Consider August 17 as a case-in-point in the energy deficiency the state's grid operator faces.

According to CAISO's market policy and performance vice president, Mark Rothleder, CAISO had expected the load on its grid to peak near 49,800 MW on August 17 during the 5-6 p.m. PT hour with available capacity near 46,000 MW, leaving a 3,600 MW shortfall. [2]

By 8 p.m. PT on the 17th, that gap would grow to more than 4,400 MW as peak load approached 47,428 MW, but capacity had fallen to around 43,000 MW due to solar generation declining with the setting sun. [3]

Faced with more inevitable forced outages on August 17, CAISO's own CEO, Steve Berberich spoke before the ISO's Board of Governors and said, "The situation could have been avoided," and further asserted that the state's resource adequacy program is "broken and needs to be fixed."

A proposed decision on the future of resource adequacy in California is due in mid-June 2021.

[2] Final Root Cause Analysis Mid-August Heat Wave; CAISO; January 12, 2021
[3] "Briefing on system operations" Phipps, John; Director of Real Time Operations for CAISO; August 17, 2020 Board of Governors Meeting

Lack of Imports During the Heatwave

The scorching temperatures drove a massive demand for energy throughout the western US, resulting in California's inability to import electricity from neighboring states as it typically does in the evenings when its robust solar resources go offline with the setting sun.

In its official analysis, CAISO detailed a series of events explaining how "realtime imports increased by 3,000 MW and 2,000 MW on August 14 and 15, respectively, when the CAISO declared a Stage 3 Emergency," but ultimately "the total import level was less than the CAISO typically receives."

Unable to import needed electricity and hamstrung by rising demand amidst record-high temperatures, the California grid suffered its first blackouts in nineteen years.

The Push to Address Climate Change

Californians, by and large, see the recent wildfires and heat waves that have ravaged the Golden State and wreaked havoc on its grid as events driven by climate change.

The state's drive toward its energy future subsequently involves not only taking steps toward making its grid resilient, but doing so in a way that minimizes its climate impacts.

The state's three main energy organizations—The California Independent System Operator (CAISO), the California Public Utilities Commission (CPUC), and the state's energy commission (CEC)—have been closely examining the recent grid failures and have submitted two reports (Preliminary and Final Root Cause Analysis) seeking to establish a root cause for the blackouts.

While they may not agree on any single culprit for California's grid woes and for the August blackouts, the big three organizations rightfully believe that establishing grid resilience and serving the state's ratepayers are the priorities.

Balancing Energy, Capacity, and Renewables for Grid Resiliency

California's renewable energy resources performed as expected in 2020, despite some slanted media coverage that may have tried to pin them with the lion's share of the blame for the August blackouts in 2020.

California has no intention of veering from the state's long-traveled path of developing and integrating more renewable energy into its generation mix.

In the wake of the 2020 blackouts, the resource adequacy proceeding in California is looking at how to ensure that the state procures energy sufficiency—i.e. electricity needed to serve the state on a day-by-day, moment-to-moment basis—in addition to capacity sufficiency—i.e. reserves that can be called on in the event of an emergency.

The proceeding is trying to establish the optimal balance between energy and capacity that can be procured within state boundaries so it can then be determined just how much reliance should be placed on imports now and in the future.

As is the case with other states in different energy markets around the US, California is at somewhat of a tipping point with so much of its generation mix dependent on renewables with inherent intermittency that renders them unavailable at unpredictable times in the day when the sun isn't shining or the wind isn't blowing.

Like many grids facing a similar predicament, California's grid of today and the future needs to ensure that its load begins to follow its supply, meaning that demand-side resources adopt an agile flexibility that can react to sudden disruptions in electricity supply due to intermittency.

Demand-Side Flexibility and Performance Measurement

In previous publications of this book, we've highlighted the importance of flexible resources to offset the intermittency of California's wind and solar resources and keep the grid's supply of electricity in balance with its demand.

Today, commercial and industrial organizations are playing an increasingly critical role in providing that flexibility via demand response participation. The question that's become even more critical as California looks to the future involves whether or not the current measurements for demand response performance in the state are as accurate as they need to be given the importance of viable demand response as a solution for grid reliability.

Many in California's advocacy trenches, including this regulatory advocate, don't think so and are fighting to make sure that customer performance with demand response is both recognized and properly measured by the state's energy organizations so it can then be appropriately rewarded in the market. (In a moment, we'll outline a key CPUC decision that is a major step in the right direction for California demand response as a crucial piece of the reliability puzzle.)

That said, it appears that the state's legislature is keenly interested in demand response and other behind-the-meter distributed energy resources as a means to shore up California's grid resilience.

CAISO, the CPUC, and CEC concluded in the Final Root Cause Analysis of the Mid-August 2020 Extreme Heat Wave report that while demand response provided load reductions when called, "the total amount did not approach the amount of demand response credited against RA requirements and shown as RA to the CAISO," and that " Additional analysis and stakeholder engagement are needed to understand the discrepancy between credited and shown RA amounts, the amount of resources bid into the day-ahead and real-time markets, and performance of dispatched demand response." [4]

2021 has been a busy year in San Francisco with the work the Public Utility Commission has produced concerning the emergency proceeding in making sure there are enough electrons to get us through whatever the summer of 2021 throws at California and its electric grid.

[4] Final Root Cause Analysis; page 6

Keeping the Lights on and Staying the Green Course

Traditionally, state regulators have focused their efforts on making sure California has enough generation sufficiency. If that focus becomes too one-sided, the state can find itself in danger of divorcing from its established climate goals.

This challenge isn't unique to the Golden State.

Across the country we find energy markets wrestling with not only maintaining balance between electricity supply and demand but also providing resilience for ratepayers, while staying true to climate and carbon neutrality goals.

That kind of juggling act can and did get complex in a year like 2020 when a wild presidential election fanned the flames of the climate debate, COVID lockdowns drastically shifted commercial and residential load consumption, and weather events like the ones we saw in the west (to say nothing of Texas's saga in February 2021) dropped catastrophic circumstances on the grid and the people it serves.

Read more: Demand-Side Energy Management in the Time of COVID

Market Constructs Under Discussion in California

There's nothing easy about California's energy trajectory in 2021 and beyond, especially when it comes to evaluating the state's energy markets for potential revision.

The day-ahead energy market was cited in the Final Root Cause Analysis as having "exacerbated the supply challenges under highly stressed conditions." CAISO has set up rules on imports and exports. The ISO has also fixed its Residual Unit Commitment (RUC) system - which was one of the key issues that led to the blackouts in August. That the repair was successful was confirmed when no blackouts occurred under similar conditions in September 2020.

The stakeholders are reviewing the markets. While it initially appeared as though we may not see any meaningful change in 2021, the regulatory bodies have taken several key steps organizations participating or considering participating in demand response should understand.

In March 2021, the CPUC approved a decision on a number of issues that positively affect demand response in California and appear to be a strong signal the state believes in DR as a viable resource that is crucial to supporting the grid in transition.

The CPUC's proceeding and decision also address a number of generation procurement related matters in the demand response space, including:

- Raise the incentives in the SCE Capacity Bidding Programs (CBP) for 2021-2021 by 20%.
- In PG&E Capacity bidding – a modest increase of $4 for October (about a 5% increase in seasonal incentive rate); plus provide an option for customers to participate in CBP on the weekends – which would provide a 25% boost in total incentives for participating customers.
- Expand the cap in all emergency/BIP programs by 50%.
- PG&E BIP will increase all incentive levels by $1.50/kW. Moving from the current $8-9/kW to $9.50-11/kW.
- Establish an emergency load reduction pilot program (ELRP). This 5 year pilot will provide an energy payment of $1000/MWh for incremental energy curtailment during an ELRP event. This pilot, at least in the initial 2 years, will allow fossil fuel generation at a customer's facility to also be compensated if enrolled to provide response during these events.
- Authorize a virtual power plant microgrid pilot tariff in SCE for exporting DERs.
- Pre-approves new baseline options being studied to better factor performance of DR during critical heat events.

While these are steps in the right direction, there is still significant work to be done on the demand response/distributed energy resources front as California's electric grid and energy markets transition to the future.

In addition, after argument, the CPUC will be keeping this proceeding open to allow for the vast record of proposals on DR improvements to be explored and adressed. Potential developments include expanding CBP elect from PG&E to the other utilities, instituting a new measurement regime for DR, opening additional avenues for qualifying capacity and more that had been put forth in this proceeding to be examined and perhaps adopted for 2022.

The California Energy Market

California's wholesale energy market consists of a day-ahead process, a real-time process, and ancillary services. The products and services traded within the California market help CAISO serve load and meet the state's reliability needs.

The day-ahead market opens seven days in advance of the targeted trading day and closes at 10 a.m. on the day before the energy will be used. Through three progressive stages (Market Power Mitigation, Integrated Forward Market, Residual Unit Commitment), the market receives buy and sell bids, guarantees supply will meet demand, clears the price, and settles the transactions.

The real-time market is a spot market in which utilities can buy power to meet the last few increments of demand not covered in their day ahead schedules. It is also the market that secures energy reserves, available for ISO use if needed, and the energy needed to regulate transmission line stability.

Ancillary services are energy products used to help maintain grid stability and reliability. They are typically called on in response to sudden losses of generation due to a variety of reasons including loss of system frequency regulation.

Demand Response in California

Demand response programs pay organizations for using less energy when the grid is stressed or energy prices are excessively high.

The major underlying value of demand response programs in California is the resource adequacy capacity they provide for the grid.

Currently, demand response programs are administered by California's three regulated investor-owned utilities: Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.

Demand Response Programs in California

Capacity Bidding Program (CBP) The CBP is an aggregator-managed, economic demand response program that operates with Day-Ahead and Day-Of options and runs year-round in the SCE Territory and May 1 through October 31 elsewhere throughout the state.

The CBP has both Day-Ahead and day-of notifications. The program is the first CAISO calls when faced with rising demand that threatens the grid's balance. The CBP is price-triggered and is utilized frequently if there is high demand on the grid.

The Lowdown on CBP

The Capacity Bidding Program is a great program for organizations that have never participated in demand response before and provides significant flexibility to change the amount of load capable of being curtailed on a monthly basis.

Demand Response Auction Mechanism (DRAM) is a pay-as-bid program developed in 2014 under the guidance of the California Public Utility Commission as a mechanism to allow third party providers to integrated demand response directly into the CAISO system.

The Lowdown on DRAM:

The DRAM program has more restrictions to which participants must adhere in order to participate, but offers more control over event dispatch.

Base Interruptible Program (BIP) is intended to provide load reduction on the system on short-notice (15-30 minutes) when the utility issues a curtailment notice in response to a system emergency. Customers enrolled in the program will be required to reduce their load down to or below its Firm Service Level.

The BIP is the last line of defense for the California grid operator. Among its requirements is a mandatory performance commitment. The BIP is the most lucrative of the three California DR programs discussed in this section.

The Lowdown on BIP

The best-paying demand response program typically has the fewest events but also has the most restrictions and regulations with which participants must comply.

THE STATE OF DEMAND-SIDE ENERGY MANAGEMENT IN

Texas

Texas state senator Brandon Creighton was in no mood for ducked questions.

Ten days after the Texas power grid had suffered the worst collapse in its history and left millions of Lone Star State citizens without power in the frigid cold for nearly a week, the elected official from District Four appeared before the Senate Committee on Business & Commerce looking for answers.

He locked eyes with former Electric Reliability Council of Texas (ERCOT) President and CEO Bill Magness, leaned into a handheld microphone, and asked the head of Texas's grid and energy market a direct question that was on everyone's mind.

"Do you believe that our market structure is adequate, or should it be changed?"

ERCOT's CEO must have known the question was coming. The grid he oversaw had just suffered its most costly failure during the state's most devastating freeze in which at least 151 people died.[5]

Austin TX just after the winter storm

[5] Texas Department of State Health Services

On the surface, the state senator's question as to whether ERCOT's market structure was adequate could be taken as one seeking a simple yes or no answer. Prior to February 14, 2021, the answer from ERCOT's perspective would have certainly been a resounding yes, affirming with pride the belief that Texas's market structure was sound and equipped to handle adversity in all its forms.

The economic mechanisms that drove ERCOT's market had time and again worked precisely as designed to stave off blackouts and handsomely reward organizations that supplied resources to the grid in times of need.

Since it was formed two decades earlier, energy wonks from around the country have debated whether Texas's economically-driven, isolated from other US grids, energy-only market was an enviable stroke of genius or a disaster in waiting.

With the grid's February failure, skeptics had more than enough damning evidence to make a sound case for the latter.

Given that many believe the freeze that had crippled the usually summer-peaking system was not a once-a-lifetime storm but rather one that may be once-every-few years, the implied question the senator posed was *could a different market design have prevented this disaster and will the market be prepared to handle such calamity in the future*?

In the tragic wake of the grid's February failure, everything about ERCOT's market is under interrogation.

Should ERCOT adopt a capacity market and bolster its energy reserves beyond the tight reserved margin it has relied on to keep costs down for ratepayers?

Should ERCOT subject itself to the Federal Energy Regulatory Commission's jurisdiction by connecting its grid to the rest of the US to enable imports in times of need?

Is it time to review scarcity pricing with a careful eye on whether paying $9000/MWh for electricity during a crisis is beneficial to the grid and the citizens it serves?

ERCOT's CEO looked back at the senator who'd posed an ostensibly simple question about the future of the Texas grid and market. He leaned into his own mic and stammered a torrent of fillers including "uh", "I mean", and "like I say" before landing on a complete thought:

"I don't think I have a real good answer to that."

Mr. Magness was fired on March 5, 2021.

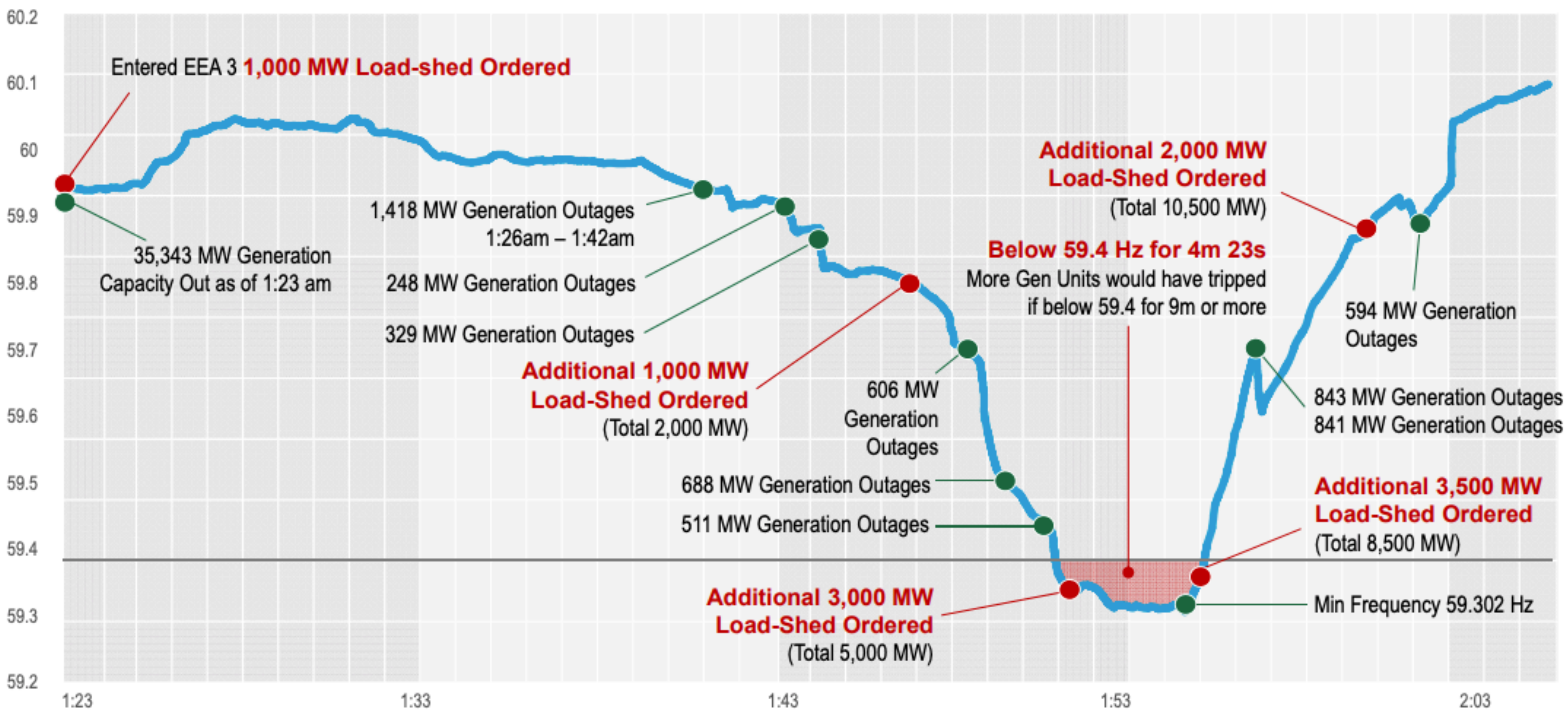
The question as to what's to come of ERCOT's market has yet to be answered.

What Happened to the Texas grid on February 14 and 15, 2021?

A week prior to the event, the Texas grid operator, ERCOT, projected high demand on the grid in anticipation of what appeared, at the time, to be unseasonably cold temperatures in the weather forecast for the coming week.

By Thursday prior to the event, ERCOT had predicted high demand, yet neglected to communicate the likelihood of demand response events being called on the coming Monday and Tuesday. What ERCOT couldn't have anticipated at that time was just how much worse weather conditions would deteriorate over the weekend and how demand forecasts would increase as temperatures dropped.

On Monday morning, just after midnight, ERCOT called its first demand response deployments, curtailing about 2,000 MW from the grid.



While demand response performed well, meeting or exceeding aggregate obligation according to [ERCOT's official reports](), the plunging temperatures proved to be too extreme for Texas's generation fleet. Generators of all variants of energy resources—from natural gas to wind, coal, and nuclear—began to trip offline due to the extreme cold.

At 1:23 a.m., more than 35,000 MW of ERCOT's generation capacity had tripped offline. At that time, ERCOT entered Energy Emergency Alert (EEA) 3, ordering rolling blackouts on the grid which removed 1,000 MW of load.

At about 1:48 a.m. Monday morning, the grid frequency dropped significantly from about 59.7 hz to almost 59.3 hz. The situation was dire. Had the frequency dropped below 59.3 hz, the grid would have gone into uncontrolled blackouts, leaving much of Texas frigid and without power for potentially weeks.

At that critical moment, ERCOT called for an additional load of 3,000 MW to be removed from the grid by utilities. Those drops in load, achieved largely by more rolling blackouts, which drew the understandable ire of Texas residents and made the national news, enabled the grid's frequency to recover.

The blackouts would remain until Thursday, February 18 and the emergency conditions were lifted Friday morning around 10:00 a.m. local time.

The Blackouts' Effects on the ERCOT Grid

ERCOT's grid has always been one to achieve its yearly peak in the summer when temperatures are scorching well above 100°F. Clearly, that isn't the case anymore.

At the grid's worst point during February blackouts, 52,277 MWs of generation were offline, which amounts to roughly half of ERCOT's *total* generating capacity. ERCOT was not prepared for losing so much of its generating fleet during a winter storm. Now, the question among Texas energy organizations is how to prevent such future catastrophic grid failures in the future.

ERCOT, the Texas Public Utility Commission (PUC), The Texas Railroad Commission (which regulates the natural gas industry) and the state legislature have more than their share of their work cut out for them as they tackle the problem in 2021 and beyond.

The Impact the Event had on ERCOT's Future

In 2011, the maximum load shed ERCOT requested during the event was 4,000 MWs. During the February 2021 event, ERCOT requested a total of 20,000 MWs, five times more than it had shed ten years ago! (see graph)

During the February 2021 event, ERCOT's load shed request lasted for 70.5 hours, ten times longer than the requested load shed in 2011, and further highlighting just how much more severe the 2021 event was.

These are staggering numbers that have led to harsh economic consequences for several energy companies that announced bankruptcy filings in the wake of the event.

Political fallout abounded as well, notably with the firing of ERCOT's CEO and the resignation of several top Texas energy officials, including all three of the state's PUC commissioners, and several of ERCOT's board members.

Consider the 2011 event in Texas, the last time ERCOT experienced rolling blackouts. Prior to what happened in February 2021, the event from a decade ago was considered a grid failure of epic proportions by energy wonks in Texas. Yet in every measurable way, the 2021 event was significantly worse by comparison.

The amount of load shed in both events is worth examining as we try to make sense of just how devastating the 2021 event was and what its lasting effect on the ERCOT market might be.

	2011	2021
Maximum generation capacity forced out at any given time (MW)	14,702	52,277
Generation forced out one hour before start of EEA3 (MW)	1,182	2,489
Cumulative generation capacity forced out throughout the event (MW)	29,729	46,249*
Cumulative number of generators outages throughout the event	193	356
Cumulative gas generation de-rated due to supply issues	1,282	9,323
Lowest frequency	59.58	59.30
Maximum load shed requested (MW)	4,000	20,000
Duration load shed request (hours)	7.5	70.5
Estimated peak load (without load shed)	59,000	78,819

** Note: "Cumulative" values for 2021 were calculated using NERC 2011 report methodology. Cumulative amount for 2021 starts at 00:01 on February 14, 2021. Source: ERCOT*

To Reprice or Not to Reprice

In the immediate aftermath of the February event, one of the many hot items the state legislature explored was whether or not to reprice the energy and ancillary markets for Thursday (February 18) and Friday (February 19) when the firm load shed ended.

On March 8, 2021, the Texas Senate passed a bill (SB 2142), which mandated ERCOT reprice what the independent market monitor (Potomac Economics) called a $16 billion "overcharge" the grid operator had levied for wholesale electricity during the February event when scarcity pricing was in effect for 32 hours after the market had returned to normal.

The bill, however, died when it failed to pass the Texas House of Representatives.

The overcharge had been a contentious topic of debate in Texas following the event. Texas Public Utility Commission Chair Arthur D'Andrea had previously argued that repricing the markets could significantly harm the market participants. The next day, Mr. D'Andrea resigned from his position at the request of Governor Gregg Abbott.

The resignation was not without a controversy of its own. On March 16, *Texas Monthly* published an article that included a recording of a phone call in which the former PUC chair discussed the financial fallout from the event with investors.

While the call in question was did not divulge confidential information, according to a PUC spokesperson, it did, in the eyes of some, present Chairman D'Andrea as having a "coziness"[6] with some of the biggest energy players in Texas.

A PUC spokesperson also stressed that the call was part of a regularly scheduled discussion "with constituent groups across the spectrum" and Mr. D'Andrea did not reveal any confidential information or make comments that he had not made publicly in his testimony.

On June 1, 2021, the Texas Legislature session ended with multiple energy related bills. None ordered the repricing of the ERCOT energy and ancillary markets.

The Texas State Capitol Building in Austin, Texas. Source: Ed Schipul

[6] *Texas Monthly*

Weatherization, Fuel Storage, and other ERCOT Measures for Grid Reliability

Much has been made of ERCOT's failure to weatherize its generation supply, especially its natural gas supply, so that it might better perform during future winters should temperatures sink to what was experienced last February. Considering the unprecedented nature of the 2021 winter, a hard question to answer, given the varying viewpoints on climate change, is whether or not the event in 2021 was a once-a-generation event or one that might happen once every few years.

The prevailing energy organizations in the Lone Star State don't appear to be brushing this past February's event aside as a freak storm. In addition to exploring and potentially enforcing weatherization efforts (including those that were proposed by FERC following the 2011 event), ERCOT, the Texas PUC, and state legislature are debating a requirement for the grid to procure more on-site fuel storage that would not be constricted should extreme weather render the fuel delivery infrastructure impotent as it did in February.

The Controversy surrounding S.B. 1278

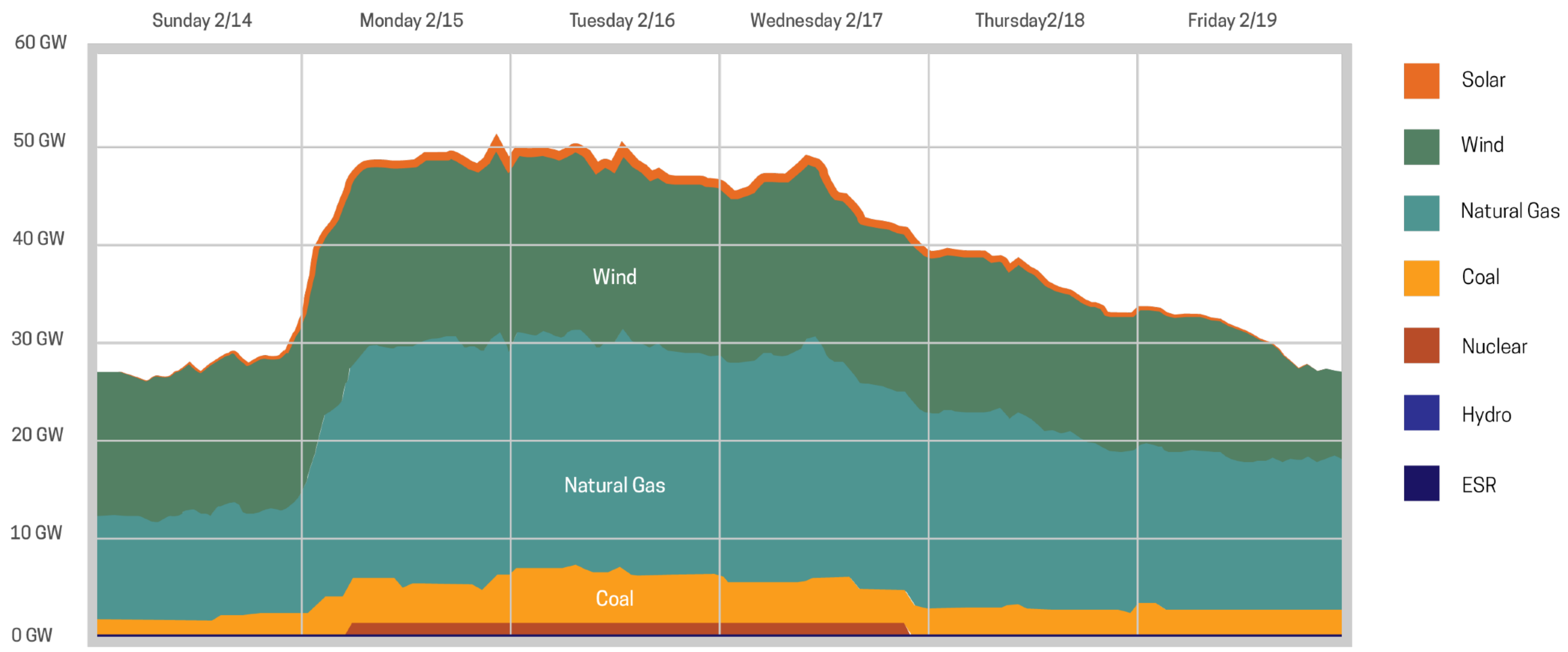
Sponsored by Senator Kelly Hancock (R) to address issues that some in Texas feel caused the February blackouts, Senate Bill 1278 addresses the limitations of intermittent resources such as wind and solar by directing the Public Utility Commission of Texas (PUC) to direct ERCOT to assign the cost of ancillary services attributable to intermittent resources and procure additional ones that would "firm up" the deliverability of these intermittent resources during peak demand periods. [7]

The bill would require the intermittent generation to directly purchase this new "firming" ancillary service from dispatchable generators.

Critics of S.B. 1278 say it's mistakenly based on the premise that renewable energy sources and their inherent intermittency as a root cause of the blackouts, instead of pointing the finger at natural gas as the main culprit.

According to an independent analysis of ERCOT's post-event data, the critics may have a point.

Net Generator Outages and Derates by Fuel Type (MW)



Outage and derate MW for Wind in this graph are based on capacity. *Source: ERCOT* *Version Date: 4/22/2021*

One of those critics—economics professor Peter Cramton, who resigned from his position as an independent director of ERCOT's board following the grid's failure—conducted an independent assessment of ERCOT's official report and concluded that renewable sources' performance during the event exceeded winter forecasts by 6.34 GW, while natural gas underperformed by 15.8 GW, which accounted for 20% of the total outages. [8]

Mr. Cramton isn't the only voice of opposition to S.B. 1278. On April 14, 2021, the CEOs from several of the states biggest and most prominent electric utilities, including Duke Energy, NextEra Energy, and Southern Company signed a letter addressed to Texas lawmakers claiming that S.B. 1278 would "unjustifiably" shift "onerous new cost burdens" to renewables.

Despite its controversy, S.B. 1278 was passed by the Texas Senate on April 14, 2021. The bill, however, did NOT pass the House, so it will not be enacted.

[7] SB 1278: Author's/Sponsor's statement of intent https://capitol.texas.gov/tlodocs/87R/analysis/pdf/SB01278S.pdf#navpanes=0
[8] Cramton, Peter "Lessons from the 2021 Texas electricity crisis; May, 17, 2021

A Capacity Market in Texas?

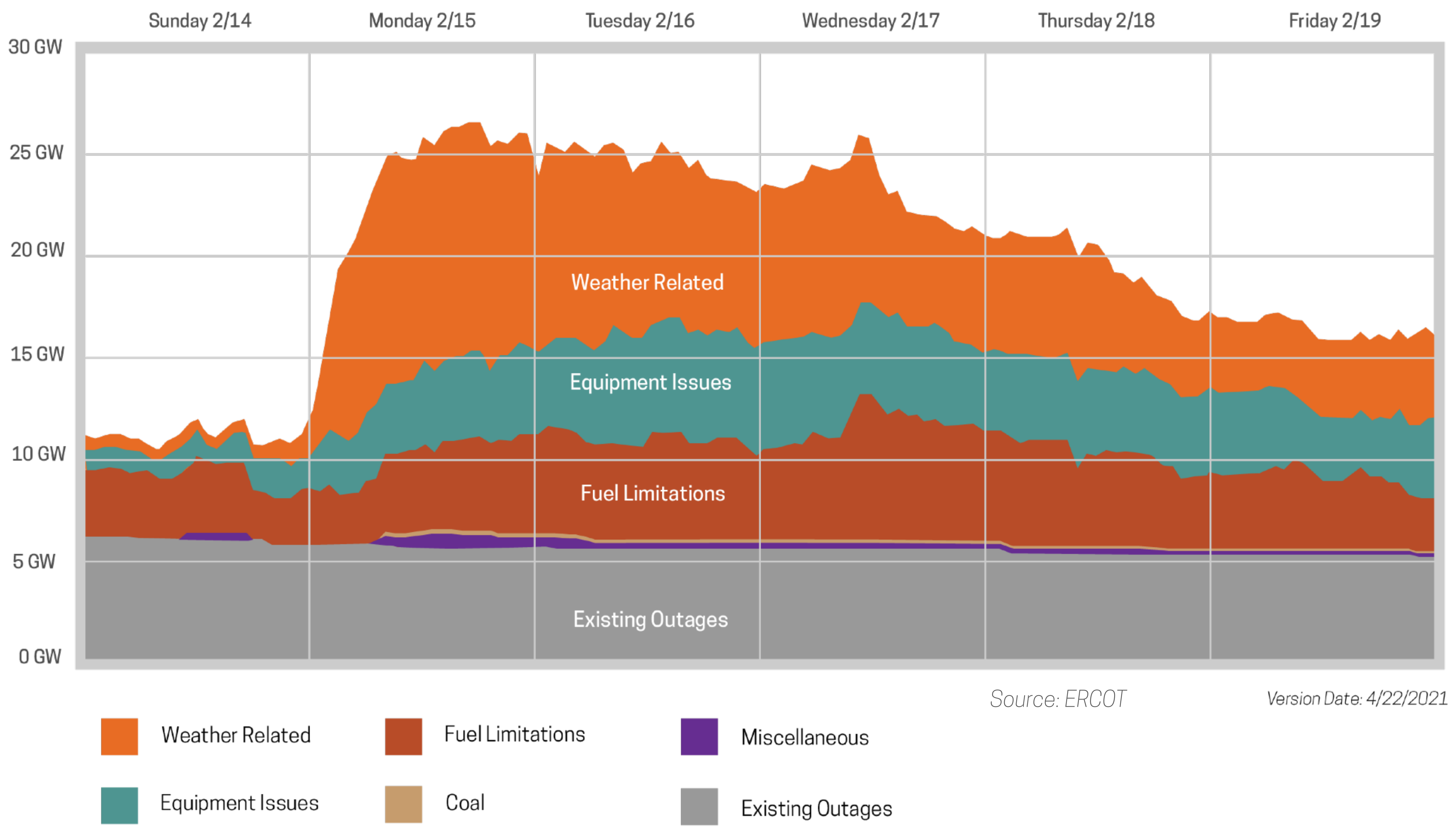
In the two-plus decades since ERCOT's formation, naysayers in and out of Texas have been watching the Lone Star State with skeptical eyes, waiting for the perfect storm when a lack of forward-procured capacity in a wholesale capacity market proves fatal to grid stability.

For decades, the Texas energy market championed by ERCOT has shunned the notion of a capacity market, stating as its reason that it did not want to burden its ratepayers with hefty capacity charges to pay from a reserve surplus of capacity as is the case in PJM, New England, and New York.

Prior to 2021, every time the reckoning seemed imminent (as it did in the Summer of 2018 and then again in 2019) ERCOT's economic-driven, energy-only market held strong, bending at times but never breaking.

The utter failure of last February has led to ERCOT and the PUCT to consider introducing a capacity market. A soon-to-be formed State Energy Plan Advisory Committee will determine what ERCOT's market requires to best maintain reliability.

Net Generator Outages or Derates for Natural Gas Generators by Cause



Would a Texas Capacity Market Have Stopped the Grid's Failure?

The short answer is no, a capacity market in Texas would NOT have thwarted the blackout that proved tragic with loss of life.

ERCOT had ample capacity going into the event, but the system wasn't prepared for the extreme cold weather and the detrimental impact it would have on ERCOT's generation resources, particularly its natural gas fleet. The event was largely caused by operational failures and not necessarily market structure.

That said, a capacity market does help ensure generators perform when needed and includes a swath of penalties that are levied if they don't.

Under ERCOT's current market structure, however, there are enormous incentives in place for generators to be available in the ERCOT market when scarcity pricing is realized and electricity prices rise to the cap of $9,000/MWh.

But the door swings both ways, as it were, in an economically driven market like ERCOT's where reward must be considered against risk.

Many generators who had sold their power forward at a fixed price and weren't able to produce electricity during the event also had to procure it at $9,000/MWh in the spot market, essentially presenting a much larger penalty than one would receive from a capacity market structure.

Should the ERCOT Grid be Connected with the Rest of the US?

Currently, the ERCOT is not connected to the grids in the surrounding sates. This means that ERCOT is NOT under jurisdiction of the Federal Energy Regulatory Commission (FERC), which oversees, among other things, the commerce related to interstate energy transmission.

Not being connected to the surrounding states' grids means ERCOT is unable to import energy in a time of crisis as was certainly the case during the event last February.

In the wake of the event, there has been talk of ERCOT connecting to the neighboring states' grids. While nothing has been formally proposed, the soon-to-be-formed State Energy Plan Advisory Committee will explore, among other items, whether connecting ERCOT's grid to the rest of the US is in the best interest of maintaining the grid's reliability.

Source: Dpysh W

ERCOT Grid Control center in Texas

Looking Ahead: Summer 2021

Traditionally, summer is when ERCOT braces for its grid to be pushed to its peak. This coming summer appears to be inline with previous peak seasons.

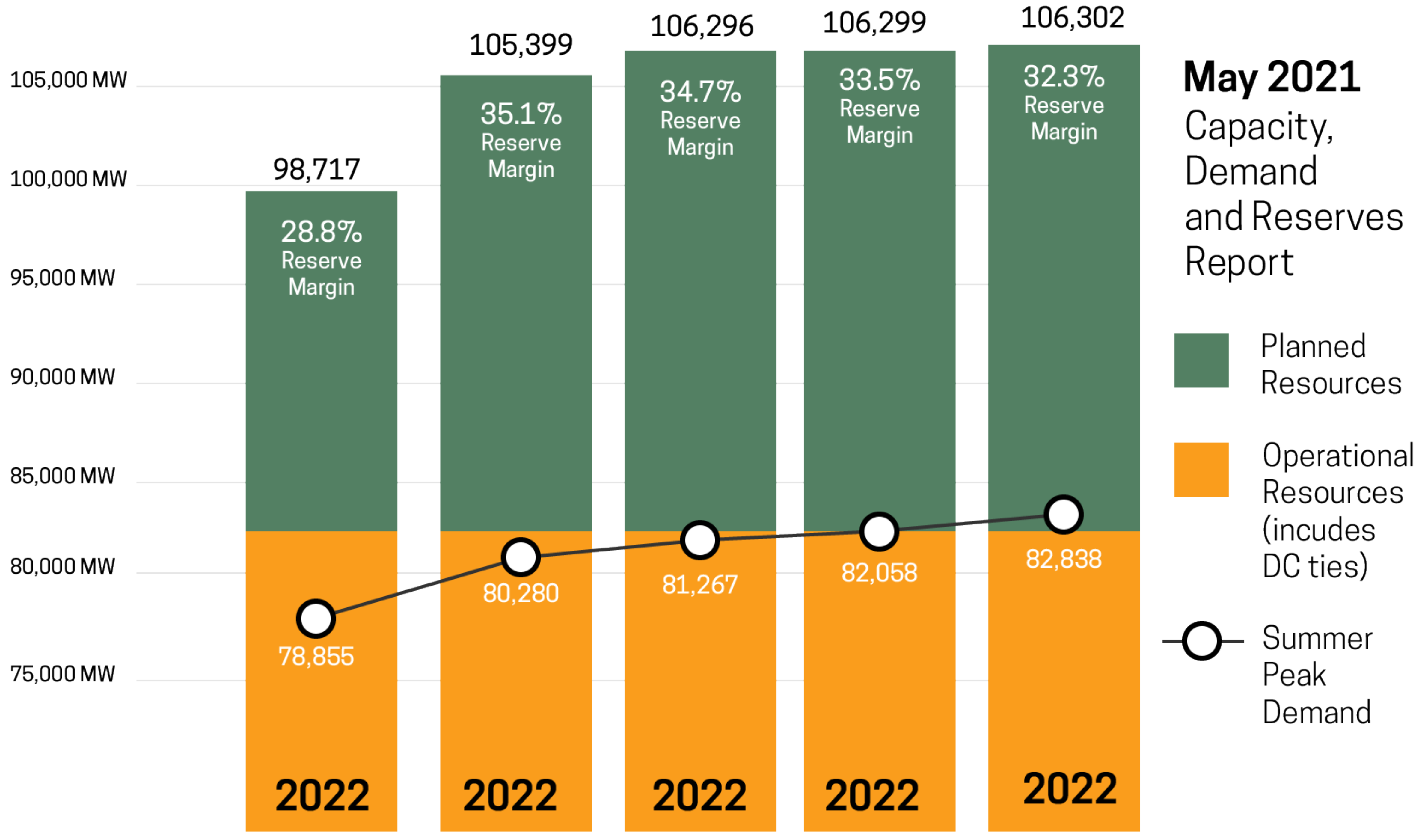
In a May 7 press release, ERCOT officials announced their anticipation of record-breaking electric demand due to the state's ever-increasing population and heat waves expected during the summer months.

In its final Summer Seasonal Assessment of Resource Adequacy (SARA) report, ERCOT anticipated that there will be enough generation to meet summer 2021 peak demand of 77,144 MW. ERCOT also announced the region will have a 15.7% reserve margin during the summer, which is an increase from the 12.6% reserve margin the region held during the previous summer.

Summer 2021
Seasonal Assessment of Resource Adequacy

74,144 MW
Summer 2021 Peak Demand Forecast

86,862 MW
Total Resource Capacity



Source: ERCOT's Summer Assessment of Resource Adequacy (SARA) report

ERCOT's Aim for Transparency

In the Final Summer SARA report, ERCOT stated that "the winter storm that occurred in February was approximately a one-in-100 event," based on available meteorological data.

Many Texans, however, still haven't shaken the chill or the harshness of the devastating event, which is why ERCOT is taking steps to bridge the divide between their organization and the ratepayers' trust.

Among those steps is the exploration of a series of low-probability scenarios related to high demand due to triple-digit temperatures, thermal generation outages, and a shortage of wind and solar generation.

During a May 6 press conference, ERCOT's Vice President of Grid Planning and Operations Woody Rickerson said, "we cannot control the weather or forced generation outages, but we are prepared to deploy the tools that are available to us to maintain a reliable electric system."

At the same conference, Warren Lasher, senior director of system planning added, "We recognize that we failed to communicate what the potential risks were, going into the winter season. These extreme scenarios have been specifically added to restore the trust in ERCOT's ability to assess and communicate the risks."

Long-Term Resource Adequacy in ERCOT

On May 6, 2021, ERCOT released its Capacity, Demand and Reserves (CDR) report, which provides a 10 year look at forecasted Planning Reserve Margins for summer (June-September) and winter (December-February) Peak Load Seasons.

According to the report, ERCOT expects its Planning Reserve Margin to increase over the next few years due, in large part, to the ongoing development of solar, gas, and wind resources as well as the retirement of Trinidad, a 235 MW gas-fired generation facility.

The report also asserts the anticipation of 1,877 MW of battery storage capacity for summer 2022, which ERCOT assumes will provide grid reliability (Ancillary Services) for short periods of time. Because battery storage capacity does NOT support customer demand on a sustained basis during peak demand hours, ERCOT assigns no capacity value to battery storage in its reserve margin calculations.[9]

[9] Report on the Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2022-2031; May 6, 2021

Demand Response in Texas

To maintain grid reliability and help organizations in Texas offset their energy use and spend, ERCOT offers the following demand-side energy management programs:

Emergency Response Service (ERS) pays organizations for using less energy when the grid is stressed or when electricity prices are high. There are two types of ERS programs: ERS 10 and ERS 30, which pay businesses for being available to curtail their energy loads within 10 or 30 minutes.

The program pays on average about $50,000-$55,000 per megawatt year.

The Lowdown on ERS:
ERS is more of an entry-level program compared with LR. With fewer regulations and technology requirements than LR, ERS is a great way to get started with demand response in Texas if your organization has never participated in DR before.

Load Resource (LR) is potentially 2-3 times more financially rewarding than other ERCOT programs for businesses who participate. The Load Resource Program is capped at 1400-1750 MW of total procurement. If more than this limit clears the market, then proration will be triggered.

Load Resource is the more advanced and better paying of ERCOT's DR programs. An ancillary service program, LR requires a 10-minute response and pays on about $86,000 per megawatt year, on average. The LR program requires an under frequency relay (UFR) to participate.

The Lowdown on LR:
The LR program is ERCOT's last bastion of defense against blackouts when demand on the grid threatens to eclipse supply. It's also ERCOT's most financially rewarding DR program and one in which commercial organizations with large curtailable energy loads should be participating to earn significant revenue and protect the grid for all Texan ratepayers.

SOP Utility Program: Each utility offering this program has specific goals. The SOP program is very similar to ERS, except it is called only in summer afternoons.

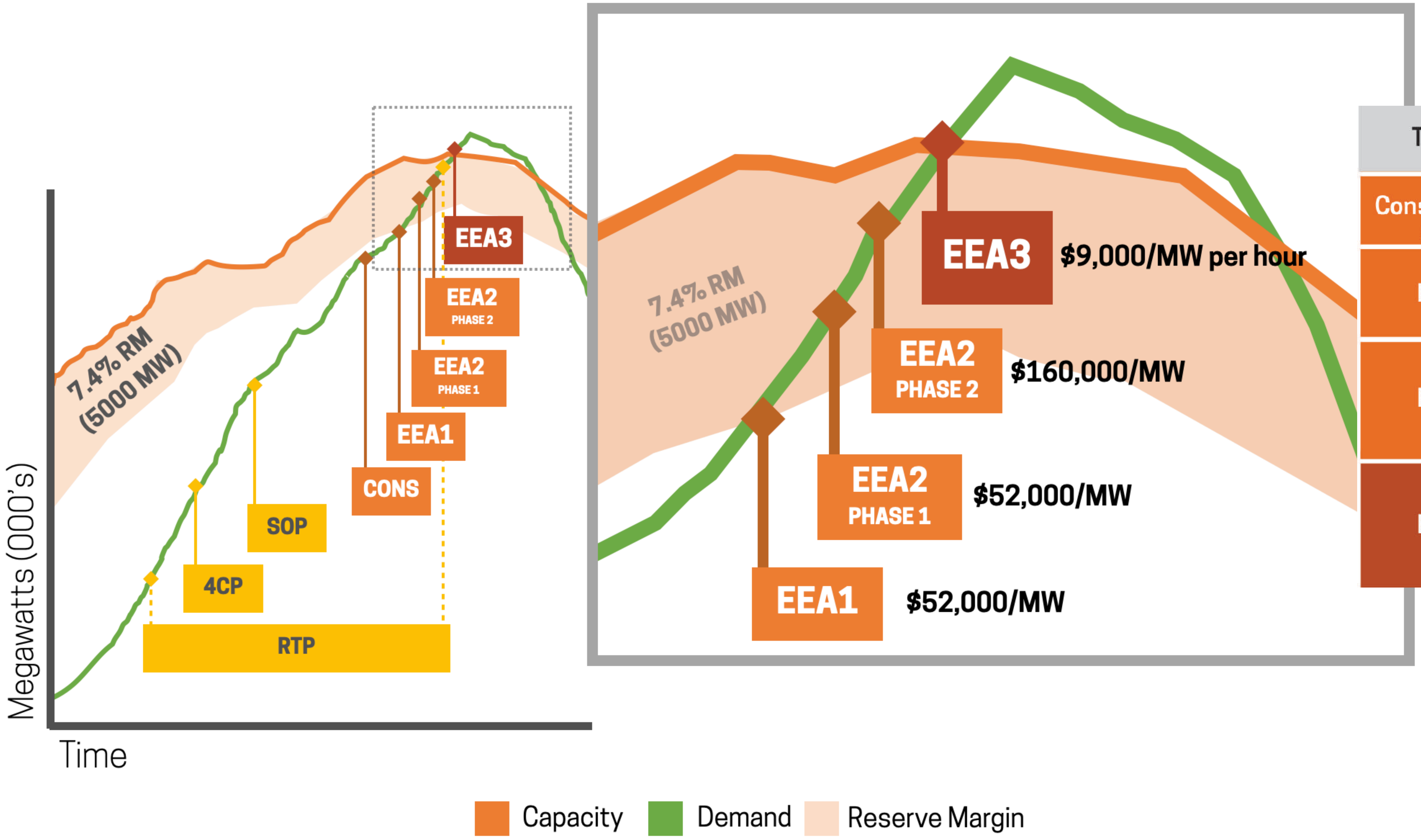
What's New to Demand Response in Texas?

ERCOT Contingency Reserve Service (ECRS)

Available in 2024, the new ECRS program is very similar to the Load Resource program in that resources must respond within 10 minutes of being dispatched and must continue to sustain their performance for "as long as they have the responsibility to provide this service."[10] ECRS differs from LR in that the new program does NOT have an under-frequency requirement.

[10] ERCOT Contingency Reserve Service Working document—protocol definition for Contingency Reserve (CR) service.

ERCOT's Arsenal for Grid Defense



TYPE	RESERVE MARGIN	DESCRIPTION
Conservation Alert	<3,000MW	ERCOT may call upon consumers to take steps to conserve power by reducing consumption.
EEA 1	<2,300 MW	**Texas Electricity Conservation Needed** ERCOT operator's authority to call on available power supplies. ERS 30 can be called at this point.
EEA 2	<1,750 MW	**Conservation Critical; Risk of Rotating Outages** ERCOT escalates to a Power Warning which allows ERCOT operators to dispatch Load Resources providing Responsive Reserve Services as well as ERS 30 & ERS 10.
EEA 3	Rolling Blackouts	**Rolling blackouts to all areas of ERCOT grid** If capacity shortage is not relieved using voluntary and contractual demand response, ERCOT will instruct utilities to rotate power outages to prevent statewide blackouts.

THE STATE OF DEMAND-SIDE ENERGY MANAGEMENT IN

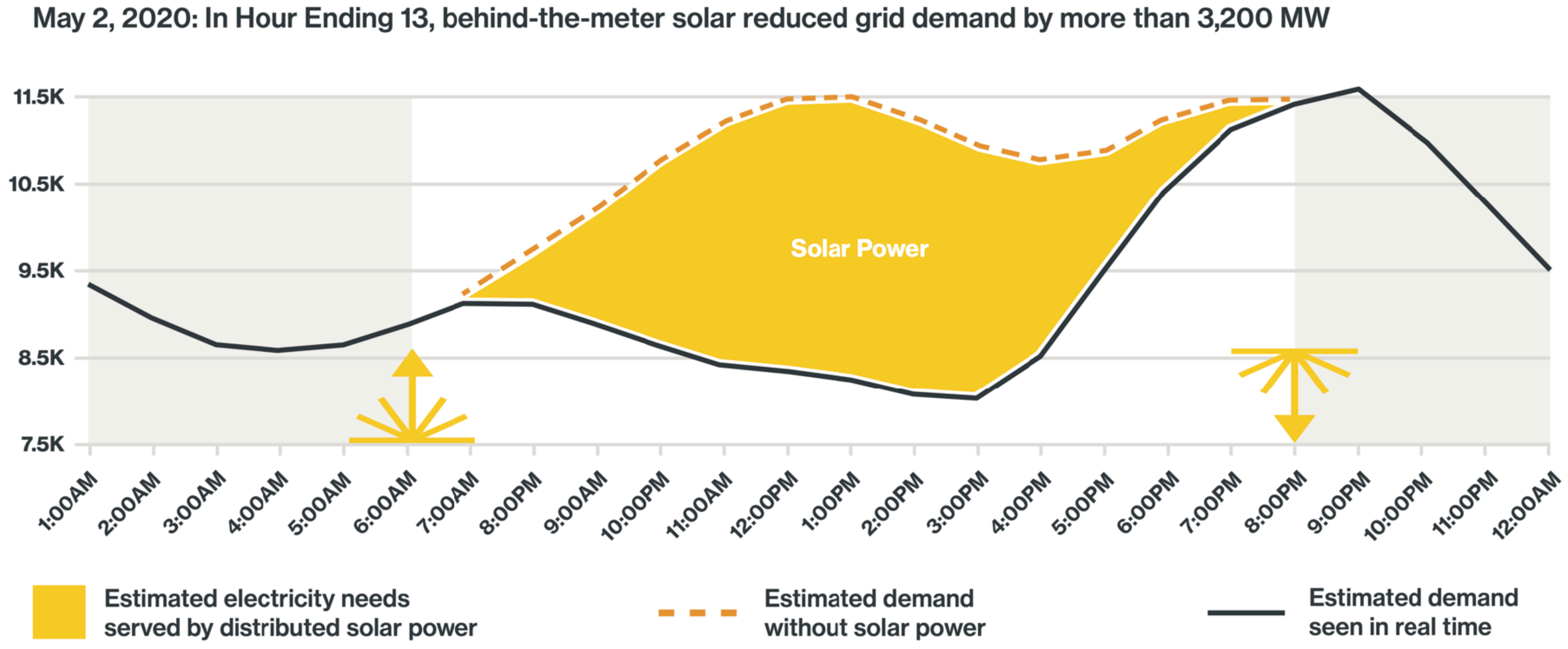
New England

Life in New England at approximately 1 p.m. EDT on May 2, 2020, was about as normal as can be expected in a region still grappling with the COVID-19 pandemic.

It's doubtful, however, that anyone living the lockdown life on a Zoom call or donning a mask for traversing public spaces was aware of the historic moment New England was experiencing. In fact, it's precisely *because* the public wasn't aware that anything was different that made the moment one that ISO-NE highlighted in its 2021 Regional Electricity Outlook report.

In the day's 13th hour, the ISO-NE grid experienced the largest dip in midday electric demand in its history, thanks to a record-high solar output of 3,200 MW.

Historic Dip in Midday Demand with Record-High Solar Output

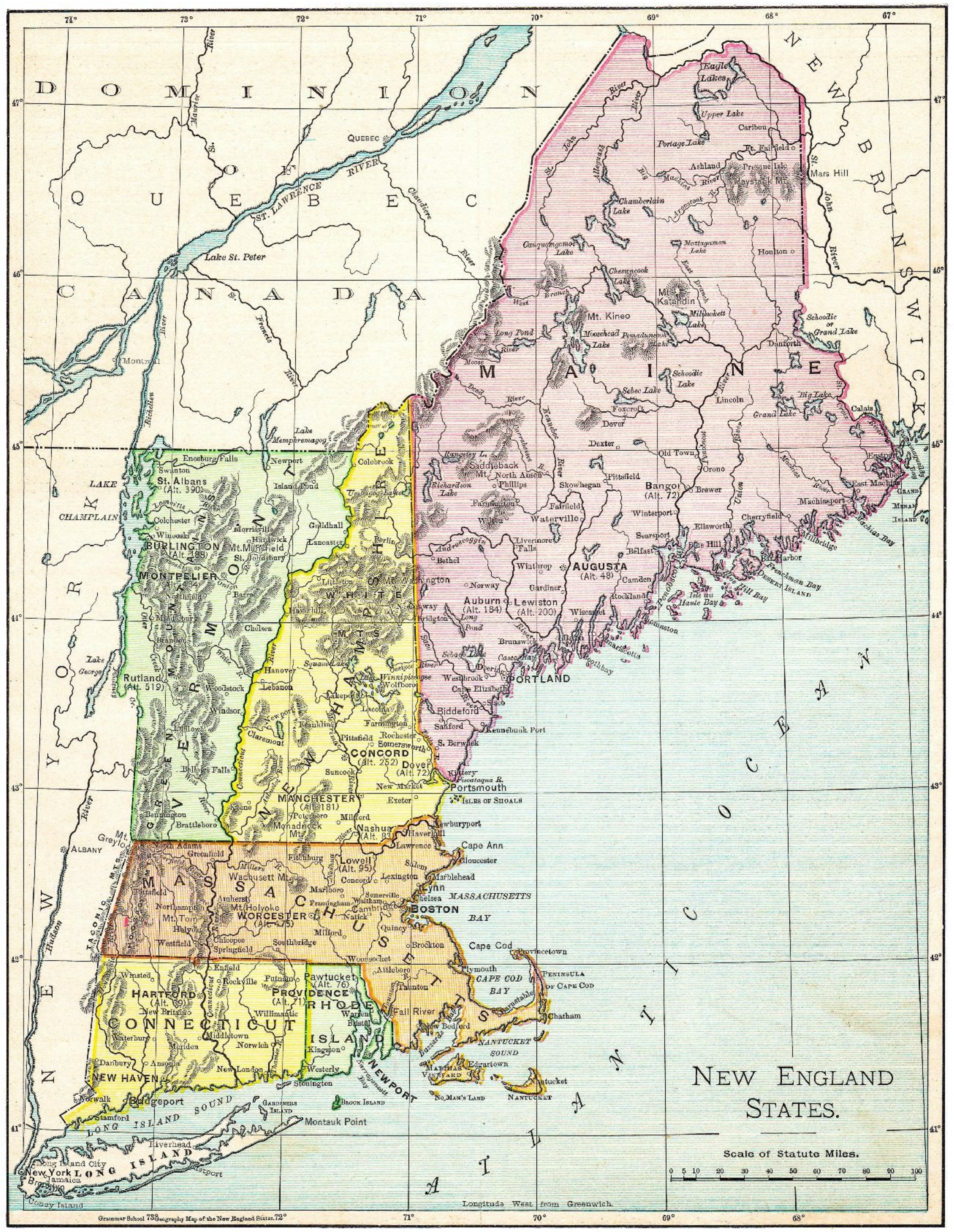


Source: 2021 Regional Electricity Outlook | ISO New England

May 2, 2020, may have been a day New England's grid operator celebrated as a sign that decades of planning, innovation, and implementation had the region's electrical grid heading toward a clean and efficient future. But ISO-NE knows an overcast sky could easily have made their day of vindication one that instead called for quick action to restore balance to a grid whose demand had eclipsed its supply.

Looking at the day's load pattern (see chart), one can't help but be reminded of the infamous "Duck Curve," a trend that's taunted the California grid for over a decade when steep evening load ramps occur each day due to solar coming offline as the sun sets and citizens come home and consume heavy amounts of electricity, at times threatening the grid's reliability.

As the amount of renewables on the system continues to grow at a rapid pace, New England states are putting pressure on ISO-NE to evolve their market to better accommodate these resources and support states' environmental policies. What's resulted is a struggle between the states, which seek a certain sense of autonomy when it comes to establishing their desired electricity generation mixes, and ISO-NE, who has countered with a series of practical measures to maintain both a reliable grid and a competitive market that fosters innovation and efficiency.



The Rift Between the States and ISO-NE

On October 16, 2020, the New England States Committee on Electricity (NESCOE) released a statement whose lengthy title gives a clear indication of the document's content.

"New England States' Vision for a Clean, Affordable and Reliable 21st Century Regional Electric Grid" is an eight-page document that outlines proposals related to three key segments of the region's energy system which NESCOE feels should be addressed with consideration to the states' interests.

1. Wholesale Electricity Market Design—NESCOE asserts that New England's wholesale electricity markets must modernize if they ever hope to achieve clean energy laws, while maintaining grid reliability and fostering affordable electricity for its citizens.

2. Transmission System Planning—the vision statement expresses support for the efficient use of existing transmission facilities and the construction of new facilities to ensure the transmission grid's reliability, efficiency, and ability to integrate clean energy resources, consistent with certain States' legal requirements.

3. Governance of ISO-NE—NESCOE urges ISO-NE to consider governance reforms that improve transparency around decision making, increase focus on consumer cost concerns, and better align with States' environmental policy .

NESCOE's submitted vision statement is intended to open the discussion and begin a collaborative process with ISO-NE and others, including the public, to ensure the region's transition to the future is ripe with clean and efficient fuel, affordable electricity rates, and a reliable, efficient grid.

ISO-NE, as we'll discuss in a moment, has taken the states' vision to heart and appears to be taking steps toward the same results expressed in the NESCOE's vision document.

Winter Energy Security Remains an Issue

The challenge of serving load and reserve requirements on a frigid winter day in New England is not new. For the last several years, ISO-NE has cited energy security as one of its greatest concerns.

The problem stems from constraints on the region's gas pipeline system as well as insufficient arrangements for fuel such as oil and liquified natural gas (LNG).

The ISO has already made some tweaks to the rules to address concerns in this area but a more comprehensive solution is needed. A couple of stop-gap measures have been approved by FERC on a temporary basis, but ISO's proposed end state solution ("ESI" - short for Energy Security Improvements) was rejected by the Federal Energy Regulatory Commission (FERC) in October 2020. The ISO won't take up this topic again until early 2022.

Stop-gap measures include:

- Giving ISO-NE the ability to temporarily retain a resource that is seeking to retire if it is needed for fuel security reasons. These changes will be in effect from June 1, 2022 through May 31, 2025; the only resources that will be retained under the provisions are Mystic 8 and 9 - a 1,400 MW combined cycle plant in Boston that runs solely on LNG.
- Providing special compensation to resources that provide "inventoried energy". This program —the Inventoried Energy Program— will be in effect from June 1, 2023 through May 31, 2025.

The Future Grid Initiative

ISO-NE believes that the key to ushering its grid and power fleet through a successful transition to a cleaner, more energy efficient future relies on a harmonious relationship between competitive wholesale electricity markets and state emission-reduction regulations.

To achieve clean-energy goals, New England states have been and continue to expand their individual energy and environmental laws to reduce carbon emissions across the region. These reductions aim to, among other things, electrify New England's transportation and heating sectors. [11]

ISO-NE is, in turn, actively seeking ways to resolve conflicts between the ISO's markets and the states' environmental goals. To maintain the integrity of its market and at the same time accommodate the states, the ISO is pursuing this initiative in two tracks.

1. The Future Grid Reliability Study is a stakeholder-led assessment of the future state of New England's power system with an emphasis on identifying reliability gaps that may emerge as the integration of intermittent resources like wind and solar continues to ramp up.

2. Pathways to the Future Grid involves regional identification, exploration, and evaluation of potential market frameworks that may help support the evolution of the region's power grid. There is an emphasis on determining how best to integrate the states' environmental objectives into the market. ISO-NE is exploring two options on this front: carbon pricing, which levies a tax on carbon emissions and a forward clean energy market, which would provide a new revenue stream to zero carbon resources.

Sometime this fall, ISO-NE expects to release the preliminary results of its study evaluating carbon pricing and a Forward Clean Energy Market, with final results coming out in early 2022.

In the meantime, ISO-NE plans to make reforms to the Minimum Offer Price Rule (MOPR).

[11] ISO-NE.com

Minimum Offer Price Rule in New England

The Minimum Offer Price Rule (MOPR) exists to prohibit new capacity resources from offering into the market below their true, i.e. unsubsidized, costs.

MOPR has garnered its share of controversy since it was enacted a decade ago. The rule was introduced to address concern about "buyer-side market power." The concern is that an entity on the load side may have an incentive to offer supply into the capacity market at below market prices in order to depress clearing prices, thus reducing capacity costs. This may degrade the economics for merchant players to the point where new capacity cannot be attracted when needed and existing resources that are needed for reliability may exit the market prematurely.

States in New England have essentially argued in recent years that MOPR infringes on their rights to determine their generation fuel mixes and unnecessarily keeps renewable resources from clearing the capacity market, requiring consumers to pay twice for capacity—once through a state procurement, and a second time to purchase capacity to meet ISO-NE capacity requirements, which the state-procured resources cannot meet due to the MOPR.

In an interview on April 5, 2021, FERC Chairman Richard Glick sided with the states when he noted, "FERC has a responsibility under the Federal Power Act, essentially, to defer to the states, in terms of state decisions about what the generation resource mix should be like. But instead, we've implemented these MOPRs, at least in the three Eastern RTOs that have mandatory capacity markets, in a matter that really attempts to block the state clean energy policies or state energy policies in general." [12]

Photo: Rod Waddington

[12] SmartBrief.com "A Conversation with FERC Chairman Richard Glick" by Sean McMahon; April 5, 2021
[13] Note that like all intermittent resources, off-shore wind is qualified to provide capacity for only a portion of their nameplate value
[14] iso-ne.com/committees/key-projects/order-no-2222-key-project

The issues at stake with MOPR are not going to be solved overnight but ISO-NE has started working on changes this month (June 2021). As part of this effort, ISO-NE intends to eliminate MOPR with Forward Capacity Auction 17 (2026/27 commitment period).

While elimination of MOPR will help renewable resources to clear the capacity market and earn capacity revenues, without accompanying changes to address the price depressing effect of allowing resources to clear at prices below their true costs, the expectation is that capacity prices will plummet.

With a few thousand MWs of state-procured off-shore wind already on the books, and thousands of MWs yet to come, it is reasonable to expect these MWs will start showing up in Forward Capacity Auctions once the MOPR has been eliminated. That said, a set of contested changes pending at FERC could facilitate off-shore wind's entry into the market a bit earlier if FERC sides with NEPOOL stakeholders over ISO-NE.

In any case, ISO-NE does feel it is important to make accompanying changes that are geared toward maintaining competitive pricing in the capacity market when MOPR goes away.

Meeting the Need for Flexibility in the Future

As the grid evolves to include an increasingly larger proportion of variable (intermittent) resources that depend on Mother Nature to provide their "fuel", ISO-NE anticipates that the need for 'balancing services' from flexible, quick ramping resources will grow.

As a result, ISO-NE may develop new types of compensation for energy resources that provide the grid with flexibility and will likely do so through new, yet-to-be-defined, market constructs. Distributed energy resources (such as battery storage, perhaps paired with renewables) and other types of flexible resources are likely to benefit from such a construct. It's possible that ISO-NE will leverage the next iteration of its Energy Security Improvements to meet these needs.

Photo: Filipe Fortes

FERC Order 2222

Order 2222 (discussed in-depth earlier in this book) requires ISOs and RTOs to allow DERs to provide all wholesale market services that they are "technically capable of providing through the aggregation of resources."

ISO-NE has done a credible job, compared with other US energy markets, of enabling DERs to participate in its markets as part of a demand response resource. As DER technologies advance, however, new participation models are needed. These resources may be unable to participate in ISO-NE's markets under current models due to their failure to meet technical and performance requirements as well as minimum size requirements.

Order 2222 aligns with FERC's desire to create a level playing field between these smaller, distributed sources and traditional generation resources. Aggregated, FERC argues, these smaller resources can meet the minimum requirements and provide the flexibility the grid needs as it transitions to a cleaner future.

Complying with FERC Order 2222 is a big effort for ISO-NE, which has initiated a detailed stakeholder process. The ISO requested an extension of the deadline for submitting a compliance filing from July 19, 2021, to February 2, 2022 and FERC recently granted this request.

Demand Response in New England

ISO-NE allows demand response to participate in its markets via the following participation models:

Passive [On-Peak] Demand Response

The On-Peak Demand Response participation model rewards participating organizations for curtailing consumption during certain specified peak hours. Unlike active resources, On-Peak resources are passive, non-dispatchable, and only participate in ISO-NE's Forward Capacity Market. Eligible behind-the-meter resources include solar, fuel cells, cogeneration systems, combined heat and power systems (CHP), and more.

The Lowdown on On-Peak Demand Response

This is a good participation model to consider for organizations that possess behind-the-meter resources described above and don't have the ability or interest in making their load reductions dispatchable by ISO-NE.There are qualifying parameters each type of resource must meet in order to participate in the capacity market, but it's worth consulting with a reputable DR provider if your organization has one or more of these resources to see if this participation model is a good fit.

Like other DR participation models in New England, this model can be 'value-stacked' with utility programs to maximize demand-side revenue earnings.

Active Demand Capacity Resource

Active Demand Capacity Resources (ADCRs) are demand response resources that participate in the capacity market by agreeing to curtail load when wholesale electricity prices reach a price level that makes it economic for them to curtail. These resources are required to offer their load reductions into the energy market; the price that they offer the load reduction at determines how often they are called on to curtail. For example, if they offer in at a price of $1,000/MWh then ISO-NE will call on them to curtail only when prices reach this level, which generally occurs only during periods when the system is stressed.

Launched in June 2018 as part of ISO-NE's price-responsive demand construct, the ADCR participation model replaced the Real-Time Demand Response (RTDR) participation model. ADCRs that can provide load reductions in 30 minutes or less are eligible to provide reserves in addition to energy and capacity. Getting credit for providing reserves is helpful not only because it allows ADCRs to participate in the forward and real-time reserve markets, but also because it helps them avoid penalties (and earn rewards) if a Capacity Scarcity Condition occurs under ISO-NE's Pay for Performance construct.

The lowdown on ADCR:

ADCR is the ISO-NE participation model that allows dispatchable loads to earn capacity and energy revenues in exchange for agreeing to curtail consumption when energy prices exceed the price threshold at which they're willing to curtail.

In 2020, despite the pandemic's chaos, there were ZERO hours in which prices reached $1,000/MWh or more . That means ADCR priced at $1,000/MWh was not called on to perform outside of the summer and winter seasonal audits that it is obligated to perform annually.

Granted, 2021 is a different year, but if we look at recent history in New England, we find that there have been relatively few high priced hours in the last five years. The most notable recent scarcity event occurred in September 2018, where prices exceeded $1,000/MWh for a little over two and a half hours due to under-forecasting of load and generator outages.

The key to maximizing DR potential in New England is to combine ADCR with utility programs—a strategy called stacking, which allows participating organizations to earn even more revenue for their curtailment efforts.

Utility Demand Response Programs

New England Electric utilities offer the following demand response programs.

Connected Solutions

National Grid, Eversource, Cape Light Compact, Unitil, and Liberty utilities are working to lower the amount of total energy our community uses during the summer months when demand for electricity on the grid is at its highest (peak demand).

To help keep their grids healthy and reliable, these utilities offer the Connected Solutions demand response program that pays businesses to use less energy during peak demand periods.

The Lowdown on Connected Solutions DR programs:
The Connected Solutions is a day-ahead notice program that typically involves 9-16 hours of curtailment per season. It can (and should) be added to other DR programs to form a robust demand-side strategy that maximizes earnings.

Daily Dispatch Demand Response

To help further reduce peaks on their distribution systems, New England utilities National Grid, Eversource, and Unitil have introduced a new demand response program called Daily Dispatch.

Daily Dispatch is designed to allow energy storage (batteries, thermal storage) to participate because of its ability to be dispatched frequently and quickly in response to rising peaks.

The Daily Dispatch program runs during the summer from June through September. The program is intended to be dispatched (as the name suggests) daily with anywhere from 30-60 events each year during the hot months of July and August. Each event is expected to last about two to three hours.

The Lowdown on Daily Dispatch:
Consider Daily Dispatch to be the Connected Solutions on steroids. Consider it from the utility's perspective. In addition to the 3-4 Connected Solutions events that might be called during the summer to reduce peaks, the utility is also using the Daily Dispatch program to reduce secondary peaks.

A given summer might involve 40 calls for participants in this program, as was the case for Eversource in 2020. But by dispatching a battery resource, customers can handle the event load and reap the rewards of this very lucrative DR program.

Clean Peak Energy Portfolio Standard

Massachusetts implemented the Clean Peak Energy Portfolio Standard in 2020; the standard is geared toward increasing clean energy production during periods when electricity demand is highest.

This is accomplished by requiring retail electricity suppliers to purchase Clean Peak Certificates for a specified percentage of their load (starting at 1.5% and increasing by 1.5% each year through 2050). Clean Peak Certificates are purchased from Clean Peak Resources - resources that either produce clean energy during certain peak hours, or reduce energy consumption during these hours.

Demand Response (DR) is one of several types of resources that can qualify as a Clean Peak Resource (making it eligible to earn Clean Peak Certificates which can then be sold to retail electricity suppliers), however, because DR measurement and verification standards have yet to be developed, these resources have not been able to qualify for certificates to date.

CPower has been actively working with the Massachusetts Department of Energy Resources to develop DR measurement and verification standards and as we publish this report in mid-June 2021, we are cautiously optimistic that DR will finally be able to qualify as a Clean Peak resource sometime this summer.

The Lowdown on Clean Peak

This program creates another potential revenue source for demand reductions during peak hours. Resource owners decide when and how much to curtail, and will earn Clean Peak Certificates accordingly. This program can be stacked with Connected Solutions to create additional value for the same load reduction.

Peak Demand Management in New England

Each year when the grid sets its yearly peak, every customer load in New England is assessed a Capacity Tag value based on the amount of electricity the organization was consuming during the annual peak hour.

ISO-NE assesses capacity costs based upon each end user's kW or MW consumed during the peak consumption hour of the entire New England system on an annual basis. The basic value of capacity, in $/kW month, is determined by an ISO-NE auction process and these values are known, for the most part, three years in advance of any given year. While capacity costs are determined by the ISO, the charges you see on your electricity bill are determined by your supplier. Capacity charges therefore vary from supplier to supplier.

This individual Capacity Tag value is then used to determine the customer's allocation of capacity charges each month during the following commitment period (commitment periods run June through May). Capacity charges can account for 20-30% of an organization's monthly electric bill.

Peak Demand Management involves an organization reducing its electrical consumption when Capacity Tag values are assessed by the grid, thereby lowering the organization's capacity charges the following year.

Some New England utilities offer additional payments for reducing load during these peak hours, allowing customers to execute one strategy to earn revenue while saving on capacity charges through peak management.

If your organization can curtail your energy consumption during periods of peak system load, you will lower your capacity value (cap tag) which in turn will potentially reduce your power costs. Since the peak hour can only be confirmed after the summer peak periods are over, any end user consumption reduction made during the peak hour will be recognized with reduced charges on your power bill in the following year.

Peak Shaving vs Demand Response in New England

New England is one of the few energy markets in the US in which organizations do not have to choose between peak shaving and demand response. They can do both.

In many cases, the curtailment strategies used for DR can also be used to reduce load on days when the ISO-NE grid is peaking and cap-tag values are assessed. Organizations looking to optimize their savings and earnings with demand side energy management can and should do both.

THE STATE OF DEMAND-SIDE ENERGY MANAGEMENT IN

PJM

On March 23, 2021, the Federal Energy Regulatory Commission (FERC) led a technical conference session whose primary discussion topic concerning PJM involved the regional transmission operator's capacity market construct and its impact on the region's states.

The heart of the discussion centered on how a 2020 FERC regulatory change interacts with state energy policies. The Minimum Price Offer Rule (MOPR) affects the manner in which certain energy resources can bid into PJM's capacity auction if they are receiving a subsidy under a state law, an issue that had been at the white-hot core of a rift that for years had been building between individual states within PJM and the market itself.

The controversial rule change is pending several court challenges, and the March technical conference was presided over by the newly appointed chairman of FERC, who did not support the 2020 change.

At the close of the conference, FERC invited interested parties to formally submit comments on a litany of topics and issues presented for the Commission's consideration. On April 26, 2021, 45 state legislators in PJM signed their names to an official filing which made their opinions on the matter clear.

"In recent years," said the states in summarizing their position, "developments in the PJM market have presented considerable obstacles to achieving these state clean energy goals and constituent responsibilities. Primary among our concerns is application of the minimum offer price rule (MOPR) to state-supported clean energy resources in PJM's capacity market."

The concern of several states had become significant enough to lead some states to consider leaving the PJM capacity auction and procuring their reliability needs through alternative means such as the Fixed Resource Requirement (FRR), a mechanism that could allow utilities to procure resources to meet future demand outside PJM's capacity auction.

Source: FirstEnergy Corp

No state has gone so far as to defect from the PJM capacity auction, but one large utility decided to do so on its own without regulatory approval (which was not required). While the utility likely had its business interests in mind when making this decision, the MOPR rules were cited as a factor.

Resolving this issue quickly in a way that harmonizes state and federal policy is important for customers, because the potential costs of a fractured PJM market are more than financial.

As a multi-state market, PJM has long relied on its size to achieve efficiencies because it is dispatching a very large system and has more options to dispatch and re-dispatch its system to meet demand or constraints.

At the same time, PJM can achieve economies of scale by operating this large system with consolidated operations and market settlement functions that works well across the massive footprint.

All the while, PJM's size and efficiency helps its system maintain reliability while also attracting innovation and investment.

This early step in the transition to the future has been bumpy with states arguing that PJM's market design stymies individual states' pursuit of a cleaner future in an environment hampered by climate change, and PJM needing to maintain its status as an interstate market and limit the effects of one state's policies on other states.

The issue of how to reconcile state policies with PJM's market design has caused the mid-Atlantic region to become fraught with conflict in ways not seen in the two decades of deregulation.

Source: FirstEnergy Corp

The Minimum Offer Price Rule in PJM

The heart of the controversy between the states and PJM isn't all that dissimilar in principle to what we're seeing in New England, where states contend that their ISO's policies are a barrier to their being allowed to procure the clean, renewable fuel mixes they desire.

Like New England, PJM has implemented a Minimum Offer Price Rule (MOPR) to prevent subsidized resources from offering into PJM's capacity market (the Reliability Pricing Model) at an artificially low price that could potentially force traditional, unsubsidized resources out of the market and possibly to premature retirement.

FERC's new chairman, Richard Glick, seems to be leaning toward the state's position on MOPR. His statement from an April 5, 2021, interview:

"FERC, in my opinion, has meddled in the markets. And instead of even addressing proposals that came from regions, at the Commission, the majority of the Commission, their attitude was, 'Well, we know better than the regions, so we're going to tell them how to do their business.' And so what we've done is, I believe, both unlawfully, and in a matter that is clearly bad policy, that we have essentially really made it very difficult for regions and states in those regions to promote the kind of generation resources they want to promote." [15]

Chairman Glick has said that he prefers regions such as PJM work with their states to address these issues and to then come to FERC with an appropriate proposal.

The 45 state legislators from PJM states who filed comments with FERC asked for the elimination of MOPR and for the Commission to, in the interim, revisit the rules around the Fixed Resource Requirement (FRR), which would allow utilities in some PJM states to procure resources to meet future demand outside PJM's capacity market.

While FERC's Chairman may side with the states on the issue of resource procurement autonomy, the Commission as a whole hopes states will stay in the capacity market. As of this writing, FERC is in the midst of a series of technical conferences aimed to make staying in the capacity market more appealing to states by highlighting a series of long-term clean energy goals.

Exactly how the issue between the states and PJM will be resolved remains to be seen. FERC's new chairman has indicated, however, that if no consensus is reached in time for the Commission to implement a new rule to replace the existing MOPR before PJM's December 2021 capacity auction, he himself would urge FERC to take unilateral action to resolve the conflict.

[15] A conversation with FERC Chairman Richard Glick

Will States Allow Utilities to "Defect" from PJM's Capacity Auction?

PJM's capacity market has strong fundamentals. As the MOPR controversy dies down, we would expect that states would not feel compelled to order their utilities to defect from the capacity auction.

That said, Dominion Energy, an electric utility in Virginia, did defect. In doing so the utility made the decision to become a self-supply entity referred to as, as we just described, a Fixed Resource Requirement or FRR Entity.

Dominion Energy became an FRR Entity without state regulatory approval on the basis that approval was not required. The reasons for the utility's defection from PJM's capacity auction appear to be more related to an opportunity for Dominion's business than to any problems with the PJM market, itself.

Our opinion is that having a large common market for capacity in PJM is good for customers because it promotes competition and efficiency.

A strong PJM capacity market structure with prices that will rise and fall based upon bona fide market fundamentals is a good outcome for customers.

Moreover, having a common market rather than a balkanized market with less transparency is good for innovation as well as for new entrants and investment.

FERC Order 2222 in PJM

If you'd like a detailed but understandable explanation of FERC Order 2222 and haven't read the article at the beginning of this book "FERC 2222: A Primer for Understanding Crucial Legislation" by CPower's Bruce Campbell, do it now. It's a worthwhile read for seasoned energy wonks and neophytes, alike.

To summarize from FERC:

"Order No. 2222 will help usher in the electric grid of the future and promote competition in electric markets by removing the barriers preventing distributed energy resources (DERs) from competing on a level playing field in the organized capacity, energy, and ancillary services markets run by regional grid operators."

In last year's edition of this book, we likened PJM's speed at which the RTO moves to integrate new resources into its markets to the tortoise in the timeless fable *The Tortoise and the Hare*. Instead of sprinting ahead in the race to a greener future and creating the proverbial three problems to solve one, as markets like California and New York have done, PJM prefers the slow and steady approach, which partly explains why there are currently few opportunities for behind the meter DERs to participate in PJM's wholesale markets.

FERC 2222 aims to change that, but it won't happen overnight. FERC has granted PJM an extension for the deadline to file compliance with the Order to February 1, 2022.

Until then, PJM will be hard at work identifying challenges and proposing solutions to implement the Order and to ensure full-compliance with its mandates. [16]

[16] FERC ORDER 2222 DIRS – EDC Coordination Workshop EDC Governance to Guide Coordination Efforts and PJM Strawman Reflections 4/16/2022

What the 2022/23 Base Residual Auction Means for Demand-Side Resources in PJM

Originally scheduled for May 2019, PJM's annual capacity auction, the Base Residual Auction (BRA), was postponed until June 2021 while FERC considered approval of new capacity market rules, specifically the Minimum Offer Price Rule (MOPR).

This was the first capacity auction post-COVID and the start of the delivery year is only a little more than a year away as opposed to the usual three.

According to [PJM's official press release](), the auction produced a price of $50/MW-day for much of the PJM footprint, compared to $140/MW-day in the most recent auction in 2018.

While opinions vary as to why such a decrease in the price of capacity occurred, most agree that the COVID pandemic and a delay in the auction due to a regulatory impasse over MOPR rules were contributing factors.

How COVID Affected the Capacity Auction in PJM

In PJM, each customer's capacity contribution (peak load contribution or PLC) for a given year is set during the *previous* year. That means PLCs for 2021 were established during 2020 when commercial demand for electricity was low during the lockdown.

While low capacity contributions translate to low capacity charges incurred, they also affect the amount of demand response a given organization can provide.

The June 2021 capacity auction took place *before* electric demand in the commercial sector in PJM had the chance to return to pre-lockdown levels, which resulted in many demand response providers offering lower volumes into the auction.

That the auction occurred on the heels of the pandemic and a return to normalcy wasn't the only bit of ill-fated timing that appears to have affected the amount of demand response offered into the capacity auction.

According to [PJM's official report of the 2022/23 Base Residual Auction](), 8,811.9 MW of the 10,513 MW of demand response cleared the auction. The cleared DR is 2,313.9 MW less than that which was cleared in the 2021/2022 BRA.

Unlike normal years, this was NOT an auction with the traditional three-year forward commitment. The delay brought about by MOPR meant the auction took place less than a year before demand response participants were expected to participate. As of this writing, more analysis is needed, but it appears that DR providers in PJM offered lower volumes of DR from existing customers and did not fully commit to signing up new customers.

What the 2022/23 BRA Says About the Future of Demand Response in PJM

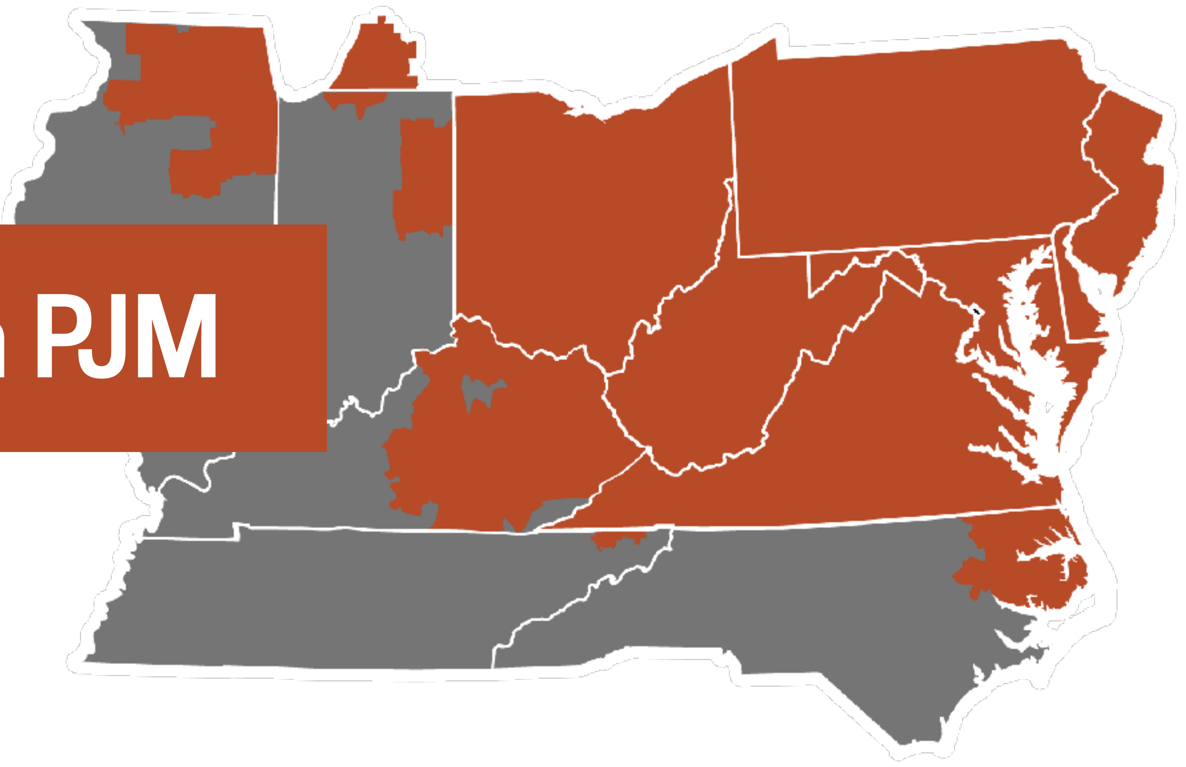
Customer interest in demand response has historically remained strong even during periods of relatively low prices.

This is the case in part because the price of capacity is correlated to the capacity reserve margin in the system. The lower the price, the higher the amount of capacity.

But with a higher capacity reserve, as is the case in 2021, there is a somewhat reduced likelihood of having a large number of DR dispatches. While dispatches can still occur, customers seem to be willing to participate despite lower pricing, with the understanding that they are likely to face fewer interruptions.

Now more than ever, commercial and industrial customers in PJM have the opportunity to realize the benefits that demand response programs can offer, both in driving predictable, repeatable revenue streams through their existing distributed energy resources as well as contributing to grid reliability.

Source: PJM Interconnection



Demand Response in PJM

To help maintain its grid reliability, PJM offers the following demand response programs, which pay organizations for using less energy when the grid is stressed or electricity prices are exceptionally high.

Capacity Program:

Capacity Performance (CP)—PJM's capacity demand response program helps the grid maintain year-round reliability by reducing demand through curtailment events. Organizations that participate in the Capacity Performance program can earn money for being available to use less energy when the grid is stressed.

Participants pick a fixed level of consumption (Firm Service Level, abbreviated as FSL). When called upon by the grid operator, they will consume no more than that amount of electricity. Events generally happen on hot summer afternoons and cold winter mornings and last 4 hours on average.

The Lowdown on Capacity Performance:

CP is by far the most popular demand response program in PJM, due, in large part, to familiarity. The major difference between CP and the emergency DR programs of PJM's past is that CP requires year-round performance from participating organizations that must be able to contribute curtailable loads in both the summer and winter.

How Zonal Aggregation can Enable Seasonal DR Participation in PJM

CP is a year-round DR program. That is, unless the participating organization works with an aggregator, which is a curtailment service provider (CSP) that specializes in DR and takes a capacity position in PJM's forward capacity market comprised of loads contributed from other participating organizations.

This capacity is then aggregated in a way that allows an organization to participate in CP using different seasonal load values due to the aggregator finding an offsetting seasonal load match.

This practice is called zonal aggregation.

In short, zonal aggregation is what enables a given customer to contribute different seasonal load values in PJM's Capacity Performance demand response program, which otherwise requires a single year-round load drop value from its participants.

The Bottom Line:

For organizations that can accommodate the program's parameters, CP can be a lucrative way to earn revenue for helping the grid.

Backup generator use is permitted with CP, making it a strong choice for healthcare, data centers, manufacturing, large retail, commercial real estate and other industries that use a backup generator as part of its operations.

Economic Demand Response

PJM's Economic Load Response programs are available 24/7/365 and allow participating businesses to manage their electricity use in response to conditions in the wholesale energy market. Participants are notified when wholesale electricity prices are high and reduce their electric consumption, thereby minimizing the impact of price spikes, reducing the need for expensive capacity generation, and helping keep prices stable in the market.

The Lowdown on Economic DR

Compared with CP, PJM's Economic demand response program is more complicated and typically requires more hands-on attention from participants. The program is voluntary for participation, so it can be as few or many hours as desired based on bidding and then acceptance of that bid for dispatch via day ahead or real time participation.

Due to all of the above, the Economic Program has a fraction of the participants as PJM's flagship DR program, Capacity Performance. That said, Economic DR can be a good fit for more seasoned DR participants looking to build on the success they've had earning with CP.

Ancillary Services

PJM's Frequency Regulation Program is available 24/7/365.

Resources in the Frequency Regulation market must be able to respond within seconds to fluctuations between generation and consumption on the PJM grid.

Participating organizations earn money for being available to rapidly increase and decrease their usage in response to a dynamic signal and are measured on their ability to perform when signaled.

The Lowdown on Frequency Regulation

The Frequency Regulation D program is currently saturated with energy storage resources already performing at a high level. The more participants that enter the Reg D market, the less lucrative the program becomes since only the best (highest performing) and cheapest offer resources will clear the market.

It's worth mentioning again: Reg D's saturation should be considered only by organizations looking to monetize their DER capability in PJM's regulation market.

PJM's Synchronized Reserves Program is available 24/7/365 and helps the grid react to short-term disturbances. Each hour, customers may offer a price, quantity, and the hours or days in which they're willing to be available to curtail if needed.

If the offer is accepted, they receive at least their offer price and must be on-call to curtail for up to 30 minutes to within 8 minutes of an event notification.

The Lowdown on Synchronized Reserves

Like Economic DR, the Synchronized Reserve program (SR) is more complex and has faster response times than CP. SR events are more frequent than CP, but tend to last for minutes versus typically two or more hours with CP. The program is limited in the amount of MWs PJM can accept in a given zone, which means that not everyone who wants to participate in the program will necessarily be accepted.

That said, the SR program can be very lucrative for experienced, savvy DR participants.

THE STATE OF DEMAND-SIDE ENERGY MANAGEMENT IN

New York

New York Independent System Operator (NYISO)

President and CEO Richard Dewey sat in silence with a microphone clipped to his lapel and the overhead lights fixed on him and him alone.

In his mind, the 20-year veteran of the NYISO arranged the details of how New York State's grid and energy market would align in a drive toward a cleaner, more efficient and prosperous future.

When the camera rolled, Mr. Dewey spoke in a calm tone, reserved with experience yet complemented with a glint of excitement in his eyes. He laid out the roadmap for how the NYISO planned to manage the state's bulk electricity grid and wholesale energy market as New York strives to reach the brass ring of lofty climate requirements established by the Reforming Energy Vision and laid out in the Climate Leadership and Community Protection Act (CLCPA).

The fruits of the NYISO leader's work that day can be seen in a series of videos on the organization's website. They're worthwhile watches for anyone interested in understanding the future of the Empire State's grid and energy market.

While much of the information contained in the video series is also available in the NYSIO's Grid in Transition report, the sincerity and conviction of the author on display in the videos delivers the message as it was surely intended.

Across the country, energy markets are working through the growing pains of evolving to support their transitioning grids. In some cases, the battles waged between state and market are fraught with public vitriol and cries for the removal of leaders tasked with the same mission as those demanding their removal—to serve the people.

In a year dominated by the COVID pandemic, New York suffered as much as any state dealing with fallout from questionable leadership tactics within the state's government. Yet the NYISO's leader, in stark contrast, has proven steadfast by communicating with clarity his organization's commitment to helping the state's electric grid transition to a cleaner future with the help of competitive energy markets, all the while maintaining the core mission of providing economic efficiency and grid reliability to the citizens of New York.

The Reforming Energy Vision's Impact on New York Energy Regulations

Now in its seventh year, Governor Andrew Cuomo's Reforming Energy Vision (REV) continues its mission to drive toward creating a "clean, resilient, and affordable energy system for all New Yorkers." [17]

Conceived in the devastating wake of Superstorm Sandy in 2012, the REV has led to the introduction of more than 40 initiatives. Over the last seven years, several of the REV's key tenets have manifested in various regulations that have affected the New York Energy market, several of which are worth pointing out.

- The Value of Distributed Energy Resources (VDER, also known as "The Value Stack") was established by the New York Public Service Commission (PSC) to compensate energy created by DERS such as solar. The Value Stack compensates projects based on when and where they provide electricity. Compensation is in the form of bill credits.
- Utility demand response programs such as the Commercial System Relief Program (CSRP) and the Distribution Load Relief Program (DLRP) have proven to be successful in removing load from the grid in times of need and rewarding the commercial and industrial organizations who participate in the programs.
- The Clean Energy Standard (CES) aims for all of New York to be powered by 100% zero-emission electricity by 2040. The CES has been touted as the most comprehensive and ambitious clean energy goal in New York State's history. [18] According to the New York State Energy Research and Development Authority (NYSERDA), the CES is tracking toward its intermediate goal of 70% of New York's electricity coming from renewable energy sources such as wind and solar by 2030.
- Climate Leadership in the Communities Protection Act was signed into law by Governor Cuomo on July 18, 2019, and requires New York to reduce greenhouse gas emissions by 40 percent by 2030 and no less than 85 percent by 2050 from 1990 levels. The law also created a Climate Action Council tasked with developing and tracking a plan of recommendations to meet these targets.

These and other regulations, some of which we detail in a moment, seek to help decarbonize the grid as well as the entire New York economy. To achieve these lofty goals, New York will rely on demand-side resources such as demand response and behind-the-meter storage.

Additionally, market designs and the incentives they create for the resources that are allowed to participate will be paramount in ensuring that the state tracks toward and reaches its climate goals by the established dates.

[17] ny.gov/reforming-energy-vision/learn-more
[18] nyserda.ny.gov/all-programs/programs/clean-energy-standard

Source: Kevin Dooley

Buyer-Side Mitigation in New York

Buyer-Side Mitigation (BSM) helps maintain the New York energy market's integrity by preventing power providers from exerting market power by offering into the capacity market at an artificially low price.

BSM helps ensure both energy providers and generators are not able to exercise unfair buyer-side market power—a form of monopoly control over a market.

For example, energy providers that receive "out-of-market" payments such as state subsidies could have an unfair advantage over other power providers who do not receive out-of-market payments when it comes to offering in New York's capacity market, since the subsidized resources could offer into the market at a price that is lower than that of unsubsidized resources.

Allowing subsidized resources to offer into the capacity market at an artificially low price would distort the actual cost and the resulting market price of capacity when power providers compete fairly in the free market.

How FERC'S Ruling in BSM Affects Demand Response Resources in NY (in a good way)

On February 18, 2021, the Federal Energy Regulatory Commission (FERC) issued an order that overturned a portion of its previously issued Oct. 7, 2020 Order in the paper hearing on whether utility demand response programs Commercial System Relief Program (CSRP) and Distribution Load Relief Program (DLRP) are intended to provide benefits solely to the distribution system (i.e. not for providing similar services to wholesale capacity) and whether the revenues from such programs should be included in new Special Case Resources (SCR) entering the market in New York's 'Mitigated Capacity Zones' G-J Offer Floor calculations as part of Buyer-Side Mitigation.

FERC's Feb. 18 Order excludes CSRP revenues (in addition to DLRP revenues as the Oct. 7 Order did), making it much more feasible for most new SCRs to pass the Offer Floor test and not have to sell into New York's installed capacity (ICAP) market at a price point that is unlikely to clear.

Customers located in Mitigated Capacity Zones who are new to the NYISO SCR program are now significantly less likely to 1) be subject to Buyer-Side Mitigation and 2) be required to offer or sell capacity at or above an offer floor price that may not clear in the market.

Rather than run the risk of being found subject to buyer-side mitigation and have an offer floor applied (that carries with the Resource until it clears in at least 12, not necessarily consecutive, monthly Spot Auctions), DR participants will no longer need to choose between retail and wholesale markets to provide DR.

Resources capable of providing different types of DR services will be able to realize the full value, benefiting both the bulk power and distribution system operations.

The order helps to unlock the full value stack of wholesale and retail demand response values to participating customers. Subsequently, new demand response customers no longer need to choose between retail and wholesale markets in which to provide demand response resources.

Source: MTA of NY

NYISO is also continuing to work through its Comprehensive BSM Reform project, which has received a jump start following Chair Glick's recent concurrence filed in a recent FERC Order concerning NYISO's co-located hybrid storage market design. Chair Glick stated, "I write separately to reiterate my belief that it is nonsensical to apply buyer-side market power mitigation to entities that are not buyers or that lack market power." Mr. Glick went on to state, "I urge NYISO and its stakeholders to move expeditiously to replace those [BSM] rules with a model that moves beyond minimum offer price rules as a means for mediating the interaction between state policies and wholesale markets."

Mr. Glick closed out his concurrence stating that, "[i]n the event NYISO and its stakeholder cannot settle upon a replacement for its current buyer-side market power rules, then we will be left with little choice but to step in and establish such rules ourselves."

These strong words make it clear Chair Glick believes that NYISO's BSM rules in their current form are untenable and will pose a barrier to developing the grid scale and distributed energy resources, including demand response, to meet New York's goals. NYISO stakeholders will be working through potential BSM reforms during Summer 2021, with an anticipated FERC filing in the fall.

The Debate over Controlling Resource Adequacy in New York

New York's Public Service Commission has opened a proceeding, investigating whether or not it is in the state's best interest for PSC to take control of resource adequacy from the New York System Operator (NYISO) and the New York State Reliability Council (NYSRC).

The reason for the proceeding centers on the PSC ensuring that as the state charges ahead in pursuit of its climate goals per the Climate Leadership and Community Protection Act, the grid has enough capacity to serve the electrical demand of its ratepayers.

Of particular concern is whether the NYISO's capacity market rules allow for grid reliability and the drive to clean energy goals to mutually exist. Many stakeholders, including the Natural Resources Defense Council (NRDC) worry that the NYISO's existing rules for its capacity market "could prevent clean energy resources supported by state and local policies from selling in that market, thereby depriving these resources of an essential source of revenue."

In this sense, New York's plight as a state fighting for the clean sources it desires to have a fair place in the prevailing ISO's energy market isn't terribly different from what multi-state markets are currently experiencing.

NYISO President and CEO, Richard Dewey, has stated his staunch belief that it is precisely the NYISO's market designs that will spur innovation and allow for New York to both attain its climate goals while maintaining the grid's reliability. According to Mr. Dewey, "The economics have demonstrated the markets are the most cost-effective way to get that investment in New York."

Local Law 97

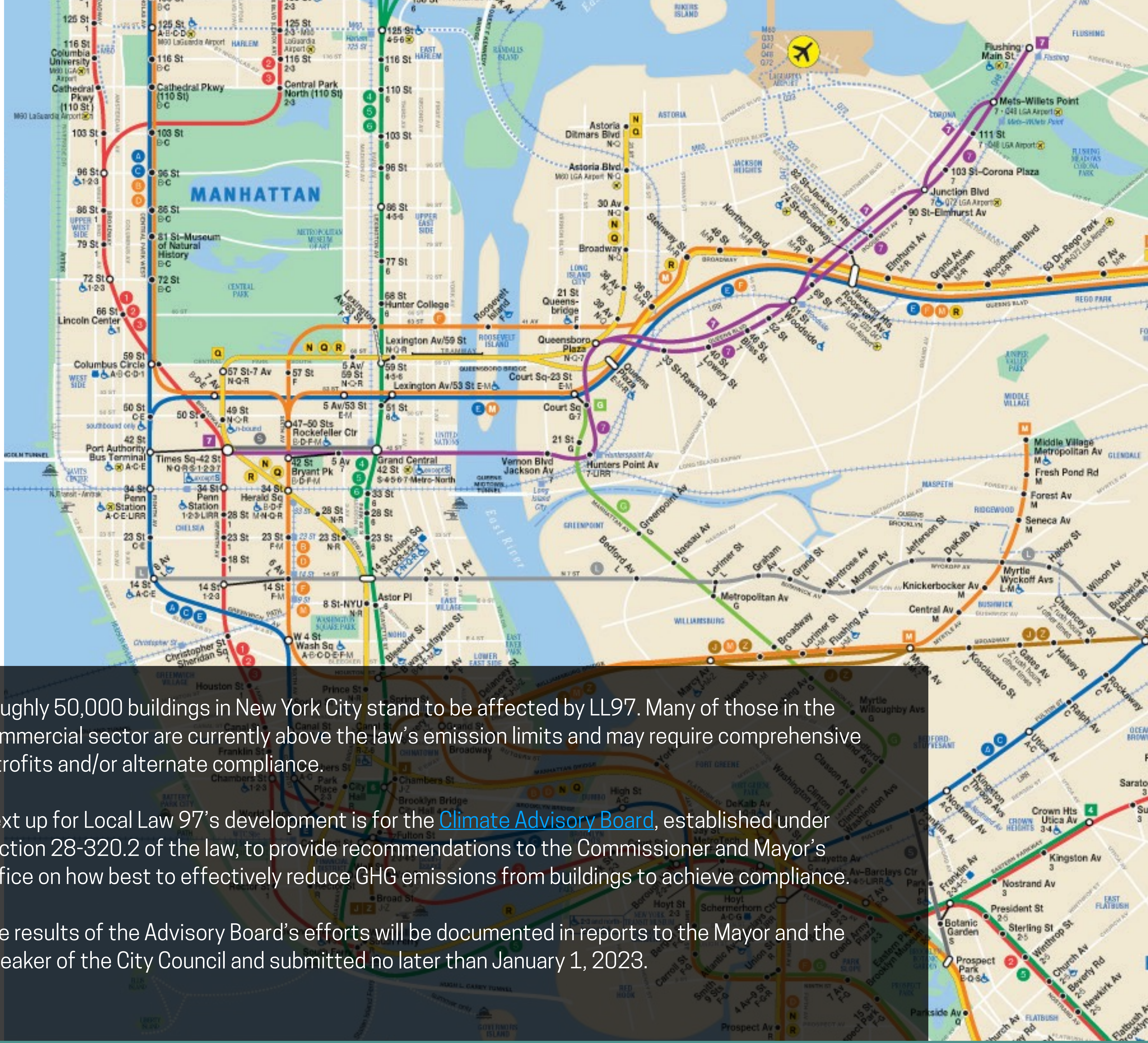
Passed in 2019 and part of New York City's Climate legislation as well as Mayor Bill de Blasio's Green New Deal, Local Law 97 (LL97) aims to mitigate greenhouse gas emissions from tall buildings in Manhattan and the outer boroughs.

The law requires 40% citywide emissions reductions by 2030 from a 2005-established baseline. The ultimate goal of the law is to reduce carbon emissions in the city's building stock by 80% by 2050.

While there are many details still in the works concerning LL97 and most of the law's intricacies won't be known until 2023, here are a few points we know today that NYC facility managers and energy planners should note:

- Compliance for LL97 begins in 2024.
- The law establishes emissions regulations on buildings over 25,000 square feet that are subject to benchmarking.
- LL97 sets increasingly stringent carbon emission limits per square foot in 2024 and 2030.
- Covered buildings are expected to cut combined carbon emissions by roughly 5.3 million metric tons, which is in-line with San Francisco's citywide emissions.

Source: MTA of NY



Roughly 50,000 buildings in New York City stand to be affected by LL97. Many of those in the commercial sector are currently above the law's emission limits and may require comprehensive retrofits and/or alternate compliance.

Next up for Local Law 97's development is for the Climate Advisory Board, established under section 28-320.2 of the law, to provide recommendations to the Commissioner and Mayor's Office on how best to effectively reduce GHG emissions from buildings to achieve compliance.

The results of the Advisory Board's efforts will be documented in reports to the Mayor and the Speaker of the City Council and submitted no later than January 1, 2023.

Source: Yoann Jezequel

DER Participation Model

NYISO received approval from FERC in January 2020 for its DER Participation Model tariffs, which will allow aggregations of DERs to participate in NYISO's markets. The tariffs create a construct to facilitate dual participation of DERs in both wholesale and retail markets. Though NYISO's tariffs were approved before FERC issued Order 2222, they largely comply with the directives contained in Order 2222. There are some areas where NYISO's tariffs need to be adjusted to fully comply with Order 2222. At present, NYISO's DER Participation Model is expected to go live in the fall of 2022.

Demand Response in New York

Currently, there are 17 demand response programs being offered to commercial and Industrial organizations in New York.

In 2016, several New York Utilities began offering two new demand response programs in conjunction with the Reforming Energy Vision (REV):
1. Commercial System Relief Program (CSRP)
2. Distribution Load Relief Program (DLRP)

ConEd has been offering CSRP and DLRP since 2009/2010. The programs will continue to run in 2021.

In 2021, New York Utilities (with the exception of PSEG-LI) will begin offering two new demand response programs alongside the CSRP and DLRP.
1. Term Dynamic Load Management (Term-DLM)
2. Auto Dynamic Load Management (Auto-DLM)

These new programs will function similarly to CSRP and DLRP, but will be procured by utilities via contract with CSPs or individual customers for terms ranging from 3-5 years as opposed to an open tariff with annual enrollment. While these new programs were born out of the NY PSC's Order on Energy Storage and were developed to help provide longer-term price certainty to storage developers, all resource types and technologies, including demand response, are eligible to participate (with the exception of diesel-fired generation resources).

NYISO's Special Case Resource (SCR) program, the longest running demand response program in NY, will also run in 2021 along with NYISO's economic programs: the Day-Ahead Demand Response Program (DADRP) and the Demand-Side Ancillary Services Program (DSASP).

The Emergency Demand Response Program (EDRP) is very similar to the SCR program, except it is voluntary and participants only receive energy payments and no capacity payments.

All of these programs can be stacked, meaning an organization may participate in more than one program and reap more revenue for using essentially the same curtailment practices.

DR and Peak Demand Management in New York

Peak demand management, or ICAP tag management as it's called in New York, involves chasing peaks, meaning the organization curtails load at the same time (hopefully) when NYISO's grid is at its peak. The result is a reduced ICAP tag value for the organization, which will result in lower ICAP (peak demand) charges on the supply-side of an organization's electric bill for the following year.

Organizations in New York can participate in DR programs and ICAP tag management. However, if the organization is participating in the SCR program and called upon to reduce load as part of any DR other program in which it is enrolled during the NYISO's coincident peak hour, the curtailment observed will be added back for the purposes of calculating the ICAP tag.

In other words, the organization would earn the revenue for it's DR participation, but it would NOT realize the peak demand savings.

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THE STATE OF DEMAND-SIDE ENERGY MANAGEMENT IN NORTH AMERICA

Volume III

AUTHOR:

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Achieving Carbon Goals with Demand-Side Energy Management

What the Electric Grid's Growth and the Internet's Have in Common

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Mathew is a well-known energy veteran with a successful track record planning, developing and implementing distributed and renewable growth strategies that leverage technological advances in solar, energy storage, intelligent software and other distributed energy resources (DERs). Mathew previously held executive roles at National Grid Ventures, KRoad DG and Yingli Green Energy focused on strategy, business development and inorganic growth through investment, partnership and acquisition.

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A Brief History of Demand-Side Energy Management

The Debate Over the Demand Response Opt-Out Rule

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As a former member of the Maryland House of Delegates and Chairman of the Maryland Public Service Commission, Ken learned how to serve the people by listening to their concerns and leading by example. His energy industry experience in the regulatory field includes extensive time in the private sector at Vicinity Energy and EnerNOC/Enel X, where Ken previously led Regulatory Affairs teams.

At CPower, Ken is now tasked with leading the company's talented regulatory team, which not only helps customers understand the complex field of energy regulation but also advocates before government bodies on our customers' behalf.

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FERC Order 2222: A Primer for Understanding Crucial Legislation

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Mr. Dotson-Westphalen has more than a decade of experience in the energy industry, primarily focused on Demand Response (DR), beginning at Constellation Energy and most recently with CPower, one of the nation's leading providers of DR and energy management services. In his role as Sr. Director Market Development, he has advocated for DR interests in ISO/RTO stakeholder groups and with state regulatory bodies, as well as managed wholesale and retail DR portfolios across the ERCOT, CAISO, and NYISO markets.

Mr. Dotson-Westphalen also spent time managing CPower's Market Compliance program. He has served on ERCOT's Wholesale Markets Subcommittee representing the Independent Retail Electric Marketers segment, was Vice Chair of ERCOT's Demand Side Working Group, chaired the Advanced Energy Management Alliance's (AEMA) Texas Committee, and currently chairs NYISO's Price Responsive Load Working Group and AEMA's New York/New England committee. Mr. Dotson-Westphalen holds a BA in Environmental Studies from the University of Vermont and is a Certified Energy Manager.

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Mr. Hourihan has extensive experience in analyzing and developing market rules in multiple energy markets across North America. His career has focused on advocating for demand side resources participation in the energy markets as a reliable low-cost option compared to traditional generation assets. Prior to joining CPower, Mr. Hourihan served as the Senior Analyst for Demand Response Partners, working with electric grid operators and utilities to maximize demand response enrollment in their various programs. He has also worked as a financial analyst for Citigroup and Hunterview LLC in their fixed-income trading departments. Mr. Hourihan graduated from Syracuse University with degrees in Finance and Management

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With more than 17 years of energy industry experience in New England, Nancy knows a thing or two about the market at the end of the US energy pipeline.

While working as the head of New England's Wholesale Regulatory Policy at Direct Energy and the Director of Market Intelligence at Customized Energy Solutions, Nancy had a front-row seat to New England's evolving grid, energy market, and the regulations that have guided both for nearly two decades.

Nancy holds a BS and MBA degree from the University of Texas at Austin. She was also the former Chair at NEPOOL, an organization of stakeholders in the ISO-New England market.

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