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PUBLIC POWER MAGAZINE

AMERICAN PUBLIC POWER ASSOCIATION

Transmission and the Markets


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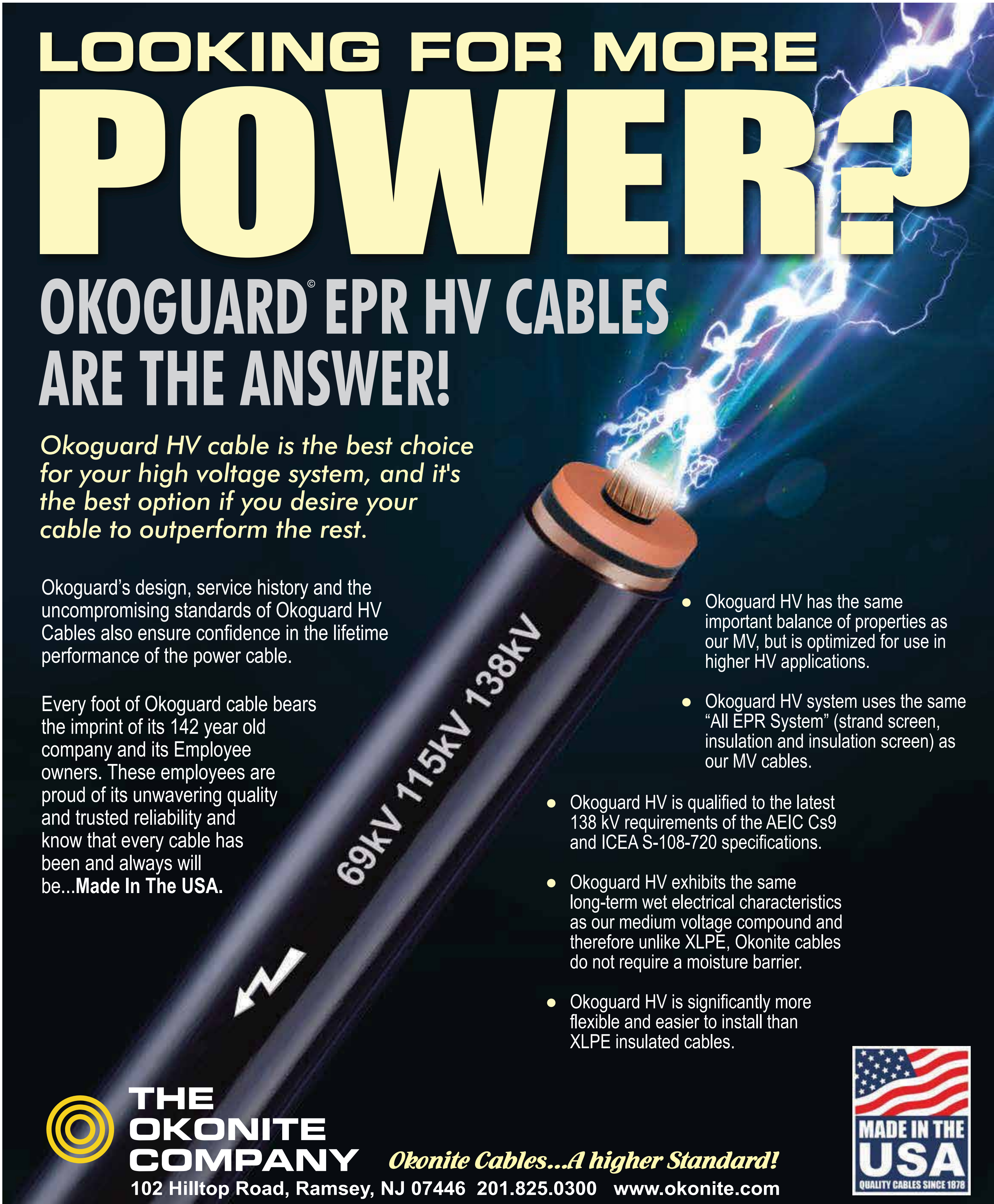
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JULY – AUGUST 2020

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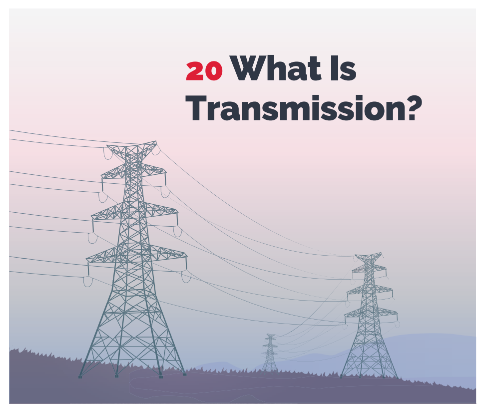

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The American Public Power Association is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We advocate before federal government to protect the interests of the more than 49 million customers that public power utilities serve, and the 93,000 people they employ. Our association offers expertise on electricity policy, technology, trends, training, and operations. We empower members to strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power.

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The great gamble of the electricity markets

BY JOY DITTO, PRESIDENT AND CEO, AMERICAN PUBLIC POWER ASSOCIATION

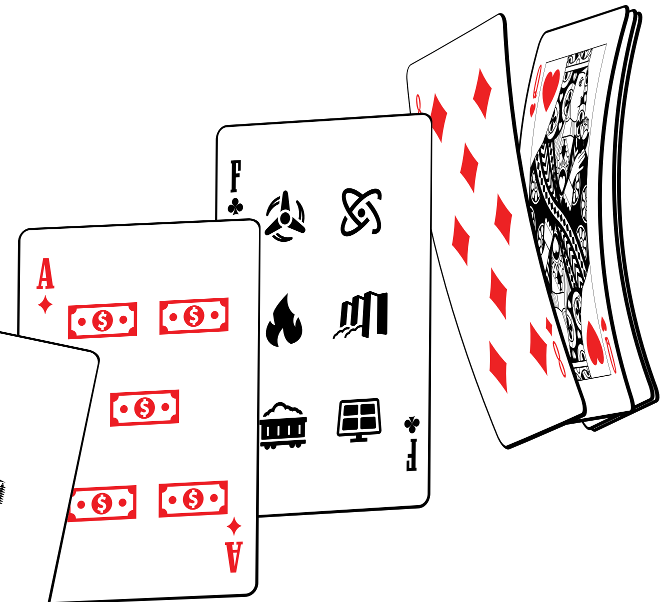
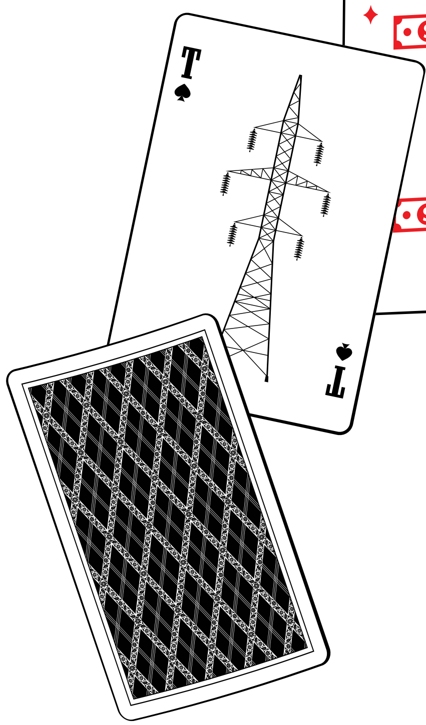
When I first started at APPA in February 2001, I had a lot to learn. While I had a crash course in electricity policy as a legislative assistant for then-Senator Chuck Hagel (R-Neb.), I still had a steep learning curve to grasp the complexity of the industry as well as the variety of players involved. Given the timing of my arrival, I was forced to quickly wrap my head around the often-competing policy objectives inherent to the regulatory bifurcation of the industry between retail and wholesale sales and how that split impacted public power utilities.

There were proposals in Congress to mandate regional transmission organizations across the country. Some people in our part of the industry were so fed up with the market power exerted by many investor-owned utilities that they were supportive of RTOs as so-called “cops on the beat,” but they did not support a mandate. Others in public power were more skeptical of RTOs in general — not because of their potential value, but because of the potential downside of what inviting more federal control might mean for local control – a fundamental tenet of public power (see page 6).

As I began to better understand the various policy drivers related to RTOs/ISOs, it became clear that I did not fully grasp their relationship to transmission access, planning, cost allocation, siting, and ownership. The history and reality of public power’s transmission ownership, transmission dependence, and power supply options all influenced how individual public power utilities and joint action agencies viewed wholesale markets. To put it bluntly, if a public power utility was transmission-dependent, an RTO might have felt like the only recourse to access affordable power supply, making the potential for additional federal regulation seem worth the risk. If, on the other hand, a public power utility either outright owned transmission, was a joint owner of transmission, or had access to significant amounts of federal hydropower, then it might not have been so interested in the gamble.

From the early 2000s to when I left APPA in 2016, RTOs/ISOs evolved significantly. The gamble wasn’t paying off for public power in the eastern RTOs, where many transmission-dependent utilities were seeking relief from high transmission costs and generation market power (enabled by transmission ownership) in the late 1990s and early 2000s. In the Midwest, it had gone markedly better. In the West and the South, only California had embarked on the experiment, and many public power utilities had been able to opt out of that market.

In the four years I was away, things shifted a bit. Sadly, the eastern RTOs are still unhelpful — if not downright antagonistic — to public power. The midwestern RTOs are still holding their own in terms of both benefits to public power and to the industry, and the West has evolved quite significantly. The most notable development has been the Western Energy Imbalance Market, a voluntary real-time market through which participants can buy and sell imbalances in load and generation (see page 32). The EIM has provided the efficiencies and costs savings of centrally dispatched markets without the risks of a full RTO.

The gamble wasn't paying off for public power in the eastern RTOs, where many transmission-dependent utilities were seeking relief from high transmission costs and generation market power

The unevenness of the RTO experiment reflects the deference the Federal Energy Regulatory Commission has shown to the RTOs/ISOs, whose policies are, in turn, molded by their largest stakeholders. But FERC blesses and codifies poor policy, such as the minimum offer price rule (see page 12), while taking a hands-off approach to the processes enabling the bad policy. In the case of the East, this has been the worst of both worlds. In the Midwest, the hands-off approach has worked better because public power and rural electric cooperatives wield more influence, and many of the IOUs in those regions have retained an obligation to serve their customers and align more often with their public power and rural electric cooperative colleagues.

There is more to the RTO/ISO story than I can get to here — stakeholders like independent power producers, jurisdictional creep into retail markets, and new technologies, just to name a few. This issue of Public Power Magazine touches on some of these other perspectives and issues.

As the RTOs/ISOs continue to evolve, and as public power utilities continue to navigate the pluses and minuses to these constructs, I come back to the "t" in RTO: transmission. The key policy matters surrounding transmission — planning, cost allocation, siting, incentives, and ownership — have not been resolved (see pages 14 and 22). While Congress attempted to address siting in the Energy Policy Act of 2005, the courts disagreed with the back-stop authority granted by that law. Granting incentives for certain priority transmission lines hasn't really worked to get the "right" transmission built (i.e., transmission with the greatest benefit to the most entities at the least cost), and FERC has ping-ponged about what is the right approach (APPA thinks the granting of such incentives must be weighed closely). Public power utilities must actively engage in the planning processes within RTOs to ensure their views are heard, but these processes often require significant resources and time. The issue of who pays is almost as thorny as siting, and a cost allocation methodology that strikes the right balance between transmission owners and other transmission users might be close to impossible to achieve. However, the policy of joint ownership of transmission is proven. Where it has happened, it has helped with siting and with cost allocation. But it has usually happened only when events have forced policymakers at the state level to bring the transmission-owning IOUs to the table with public power and co-ops.

The push for more joint ownership of transmission was a priority when I first came to APPA in 2001, and it is an issue whose time has come. As an industry, we can come together around this concept and make it a priority again. In so doing, we could hedge against our exposure to rising transmission costs while helping to ensure that beneficial transmission infrastructure gets built.

LOCAL CHOICES FOR SUCCESS:

PUBLIC POWER IN A DISTRIBUTED ENERGY RESOURCES WORLD

BY SUSAN PARTAIN, SENIOR EDITOR AND CONTENT STRATEGIST, AMERICAN PUBLIC POWER ASSOCIATION

As technology continues to disrupt how electric utilities operate, it also brings into question how regulations, costs, and other aspects of business should change or stay the same.

Central to the public power business model is the ability to engage in local decision-making about the ways in which communities get and pay for their electricity.

The tension around local control is particularly acute within regional transmission organizations, as they examine how to accommodate distributed energy resources and technologies, such as energy storage. Public power organizations within these regions are grappling with the push and pull of how they can take advantage of the benefits of these new technologies without inviting increased regulation on local operations while continuing to ensure affordable electricity for their customers.

WHY GET INVOLVED IN DERs?

For Braintree Electric Light Department in Massachusetts, which has had a 2-megawatt battery energy storage system in operation for a few years now, the lure of such technology is about savings. Bill Bottiggi, general manager at BELD, explained that the system saves the public power utility about $30,000 per month — $10,000 from being able to cap its peak summer capacity, and $20,000 in avoided transmission costs.

In addition to the battery system, several commercial customers in BELD's service area have installed solar arrays, totaling about 5 MW, which Bottiggi said helps the utility's peak shaving efforts and contributes to the city's overall environmental goals. BELD offers residential customers incentives to install rooftop solar, but Bottiggi said that there hasn't been much use of the incentives, "probably because our rate is so much lower than the IOUs around us."

BELD also installed a 4-MW natural gas generation peaking facility and is working to install a similar 4-MW generator at a large commercial customer site. Although the natural gas facility is primarily used for peak shaving, Bottiggi said that BELD does sometimes enter energy from the facility into ISO New England's real-time market when the locational marginal price gets high enough. BELD has not entered the asset into the market for the past few months, as Bottiggi said that real-time prices for energy have been about half of what they typically are because of the decreased demand resulting from the shutdowns put in place to reduce the spread of COVID-19.

Bottiggi said that the drive to develop more distributed energy resources throughout New England stems from local and state goals to decarbonize the power supply. While public power utilities are exempt from meeting the renewable portfolio standard in Massachusetts, which calls for investor-owned utilities to be carbon neutral by 2050, "we know that if we don't stay ahead of the game, then we will become regulated," said Bottiggi. He said that public power utilities in Massachusetts are proposing legislation to institute a "self-imposed" standard, which, unlike the current RPS, would include nuclear within the portfolio of allowable sources.

As more utilities look to add storage across the region, incentivized in part by ISO-NE, Bottiggi said one concern is that the ISO might try to limit how much utilities can shave from their peak.

"Right now, we can shave around 10 MW. So we pay less, but someone else is paying more," said Bottiggi. "If everyone started to do that, it would create quite the dynamic."

DISPARATE IMPACT TO SMALLER UTILITIES

A common concern surrounding the increased deployment of DERs is how doing so will affect public power utilities — both in terms of system management and in terms of cost.

On the operations side, DERs create more uncertainty about how much energy is on the system and how much is needed, opening up the possibility of imbalance in supply and demand. On the financial side, customers with DERs might be creating a "revenue imbalance" if energy generated from rooftop solar panels, for example, is compensated at a different value than the value of the generation.

Paul Zummo, director of policy and statistical analysis at the American Public Power Association, explained how some of these complications might be more acutely felt by small and community-owned utilities. As nonprofit entities, public power utilities are trying to set rates as close to cost-based as they can, so there is less room or margin for any revenue imbalance.

Adding to the complexity, DERs can sometimes participate in both retail and wholesale compensation programs, either on their own or as part of an aggregation of DERs. To ensure energy from distributed generation isn't getting counted twice – both as a wholesale and retail sale – Zummo observed that utilities would need to have advanced metering infrastructure and other technology in place. Since smaller utilities aren't as likely to have AMI, being able to support aggregated DERs would require an investment in new technologies that come with a significant cost.

"If you set up the rules in such a way as to make it much more economically viable for customers to do solar plus storage, it is going to increase the number of customers who choose this option, and if you are limited as a utility in how you can manage that, that's going to create another cost impact and exacerbate any problems you already have," said Zummo.

The Federal Energy Regulatory Commission is considering rules that would make it easier for aggregated DERs to participate in the markets. If FERC adopts these rules, it would add complexity to public power utility operations as the utilities would likely be required to interact with more with the RTO and FERC.

"Suddenly you are dealing with a major federal entity that you aren't used to dealing with … and you have to deal with a set of rules that are perhaps more complicated than the rules you are used to," said Zummo.

Reducing the financial impacts of regulation on public power utilities is a major reason that American Municipal Power, Inc., a joint action agency with members in nine states, has staff who stay engaged with FERC.

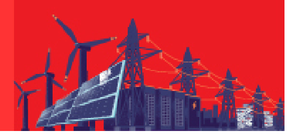
LOCAL CHOICE AT STAKE:

NET METERING

In April, the New England Ratepayers Association submitted a petition to the Federal Energy Regulatory Commission, asking FERC to find that it has jurisdiction over the sale of any excess energy from rooftop solar facilities and other customer-sited distributed generation. In June, the American Public Power Association submitted comments asking FERC to dismiss the petition, as such an order would subject hundreds of thousands of customers with distributed generation to federal regulation, and could undermine local utilities' net metering programs. Local control over net metering allows public power utilities to ensure that retail rates appropriately reflect the costs and benefits associated with distributed generation and the policy preferences of the utilities' communities.

LOCAL CHOICE AT STAKE:
EFFICIENCY AND DEMAND RESPONSE

In a decision issued in 2017, FERC stated that it has exclusive jurisdiction under the Federal Power Act to regulate the participation of certain energy efficiency resources in wholesale electricity markets.



MORE CHANGE, MORE COSTS

Paul Beckhusen, senior vice president of power supply operations and energy marketing at AMP, echoed that the generation mix is changing to more renewable sources. He cited reasons including sustainability efforts by members and decreased costs that are making renewable sources much more competitive. He also said that technologies that can help with demand side management and demand response are poised for growth.

However, the changes are also bringing added costs.

Beckhusen said that transmission costs have doubled over the past decade and that some of the regions AMP serves have seen as high as a 10% increase in transmission costs over the past year.

"Transmission costs are probably the biggest risk we have on the escalating cost of the power supply right now," he said. "For transmission, the only offset we have is peak shaving with behind-the-meter and demand response resources for the members."

AMP has undertaken several peak shaving projects, including about 70-MW of behind-the-meter reciprocating internal combustion engines and about 60 MW of behind-the-meter solar assets installed in AMP member communities, said Beckhusen.

AMP also developed a transmission arm to have more direct ownership of the transmission lines.

"If you are a transmission owner, then you are just like every other transmission owner. It allows you to be part of the process, allows you to control that part of the cost," he said. "Traditionally, on the power supply side, we owned and built generating assets to hedge our generation costs. [AMP Transmission] allows us to be a transmission owner and help mitigate those costs."

Beckhusen said one of AMP's concerns is about how the minimum offer price rule in the PJM Interconnection capacity construct will affect the development of new projects and member capacity costs.

"Any new generation resource project would be subject to the MOPR, which would not have been the case in the past, and it also will cause capacity prices to go up," he said.

SIDE EFFECT ON LOCAL CHOICE

Increased regulation at the federal or state level could also change the dynamics of relationships utilities have with developers and other entities.

"It's very important that we have local control … it just makes things so much more nimble," said Bottiggi. "It's much more expensive and time consuming [for IOUs], because they need to get approval from the state."

Bottiggi noted that typically, only the board must approve projects for BELD before it can move into the permitting phase. He said contractors have mentioned that they like working with BELD "because they know we can get stuff done quickly."

"Any mandate interferes with the ability to make the best decision locally," said Zummo. "As the local utility, you have the best sense of what resources might make the most sense to be clean."

Beckhusen added that AMP undertakes a lot of engagement to educate its members and their customers on opportunities for DER projects.

LOCAL CHOICE AT STAKE:
ENERGY STORAGE

FERC's Order No. 841 allows for storage resources interconnected on the distribution system or even behind a retail meter to circumvent state or local restrictions on customers directly selling into the wholesale market.

He said that public power's local decision making model makes such projects easier as, "AMP works closely with member communities to understand their respective system needs and community goals to assure support when subscribing a project."

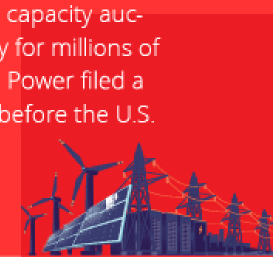
Beckhusen stressed that AMP will continue to stay engaged with FERC and other federal entities on matters that can affect costs and operations for its membership.

"It comes down to the grassroots benefit of public power and doing what it has always done well — to communicate to legislators and elected officials the real impact of their decisions," he said. "And that includes explaining and demonstrating impact on customers — residential and business."

LOCAL CHOICE AT STAKE:

CAPACITY COSTS

A FERC order stated that new public power self-supply resources and state-sponsored resources should be subject to the minimum offer price rule in PJM Interconnection's capacity construct. This creates risk that these resources will not clear the capacity auction, thus threatening the affordability of electricity for millions of customers. In April, APPA and American Municipal Power filed a petition for review of FERC's orders, which is now before the U.S. Court of Appeals for the 7th Circuit.



How a Minimum Offer Price Rule Causes Higher Prices and Reduces Competition

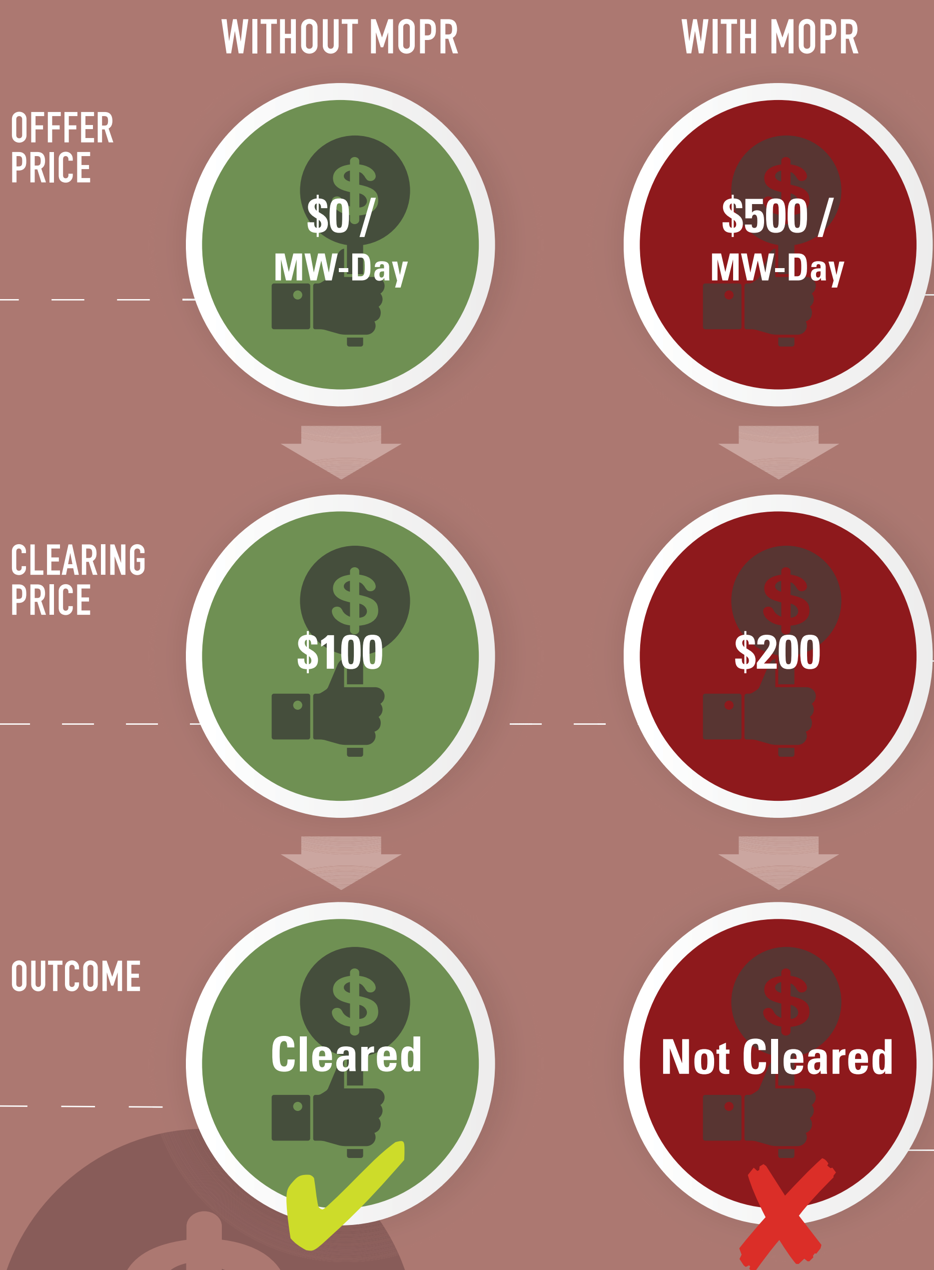
Let's say a public power utility is planning to retire a plant and needs a new generation source to replace this supply. The utility decides to sign a long-term contract to purchase power from a new wind farm. Because of the minimum offer price rule, a complex and anti-competitive provision in some of the capacity markets, that utility could be required to pay twice for that power.

In certain regional transmission organizations, the utility must offer the wind farm into a capacity auction when it will begin operating. If a utility does not have enough owned or contracted capacity to meet its peak demand plus a reserve, then it must purchase additional capacity from auctions held by the regional transmission organizations. Some RTOs require all capacity to be offered into the auction.

If there is no MOPR, then the utility can offer the wind capacity at any price it chooses. The utility would typically offer it at zero price to ensure that the resource clears the auction.

The RTO sets a clearing price based on the supply offers and the need for capacity during a specific time. If capacity is offered at a price below the clearing price, then it will clear the auction.

No further purchase necessary



With a MOPR, the utility might have to offer the wind capacity into the auction at a higher price, which increases the risk that the capacity will not clear the auction.

With higher price offers being made, the auction clearing price also increases

Additional 20 MW required purchase from auction.
If the capacity does not clear the auction, then the utility cannot count the wind farm's capacity towards its reliability requirement, and must buy additional capacity from the auction — paying for both the contracted wind power and the auctioned capacity.

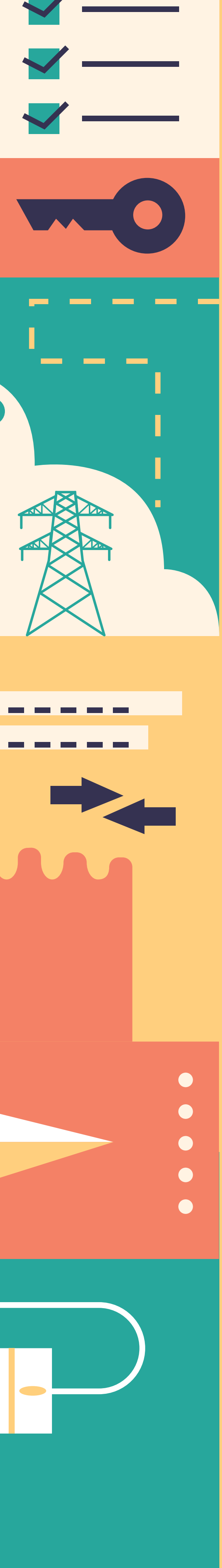
LOCAL UTILITY

Capacity needed to meet reliability requirement = 100 MW

	No MOPR	MOPR
Solar	5 MW	5 MW
Hydropower	25 MW	25 MW
Natural Gas	50 MW	50 MW
New Wind	20 MW	20 MW
Capacity purchased from auction	0 MW	20 MW
Total Capacity Purchased/Owned	**100 MW**	**120 MW**

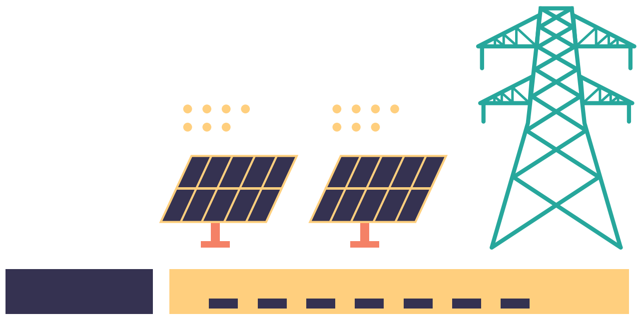
In this case, the MOPR has led to wasted money, excess procurement, and increased prices for all capacity in the auction.

In this example, at $200 per MW/Day, the utility pays $1,460,000 in added annual cost to purchase the excess capacity



FOR THE MOST GOOD: BENEFICIAL TRANSMISSION PLANNING

BY JAMES PATERSON, CONTRIBUTING WRITER



Like nearly everything else about the energy sector, transmission planning has become more complex, now involving thorny issues ranging from bigger challenges with land acquisition to more variable energy sources that don't easily mesh with the existing transmission infrastructure. The new considerations also make transmission a bigger factor in overall costs.

When the grid took shape in the early part of the 20th century, transmission development was largely about the efficient movement of power — simply getting enough to the right locations securely. Now, development is driven by new regulatory structures, new technology and energy sources, power plant competition, shifting demand, distributed generation and fast-changing power use patterns.

Even though more variables have been added to the equation, the key motivators for transmission development revolve around the familiar ones: power quality and cost.

"The two biggest factors affecting how electric utilities plan transmission are reliability and economics," said Joseph Eto, a staff scientist at the Lawrence Berkeley National Laboratory and strategic advisor for its Energy Storage and Demand Resources Department.

He is the author of more than 200 papers on issues related to reliability, transmission planning, integrated resource planning and demand-side management, including a recent paper that details the decision-making process of the transmission planning regions and, more recently, a paper that elaborates on how recent orders from the Federal Energy Regulatory Commission have affected the regional planning process.

Eto listed three factors — reliability, economics and public policy — as the key arenas for transmission planning going forward.

THE RENEWABLE EFFECT

Renewables are at the center of much of the change, according to Aubrey Johnson, executive director of systems planning and competitive transmission at Midcontinent Independent System Operator, the regional transmission organization serving 15 states in the Midwest and the Canadian province of Manitoba.

"Long-term transmission planning has always been part of MISO and utility efforts, but under the significant action to move to renewable energy sources, it is even more important now to ensure that the unique challenges ahead of us are met," he said. "As renewable penetration increases, the complexity of integrating these resources into our system accelerates rapidly."

He noted that transmission, market and operational solutions are needed "beyond what is required to connect these resources to the system now."

"Without these solutions, the energy delivered by each incremental renewable resource added to the system will be reduced, requiring more and more facilities be added to meet renewable energy goals."

Johnson noted that geography is also important, especially when regions with a lot of wind generation are more remote from major load centers.

The Missouri Public Utility Alliance, which represents 120 municipal utilities and serves three power pools, has been a key advocate for the proposed Grain Belt Express, or GBX, a major transmission line that could carry up to 4,000 megawatts of energy from wind-rich central Kansas throughout Missouri and Illinois. The project has run into a number of hurdles that demonstrate the complexity of transmission development, according to Duncan Kincheloe, MPUA president and general manager. Planners believe GBX will save the 39 affected utilities and their customers nearly $13 million annually.

Now, following several years of regulatory and landowner tangles, it passed a major legislative hurdle in May and is on track to be up and running by 2024, said Ewell Lawson, vice president of government affairs, communications and member relations at MPUA.

COMPLEX RELATIONSHIPS

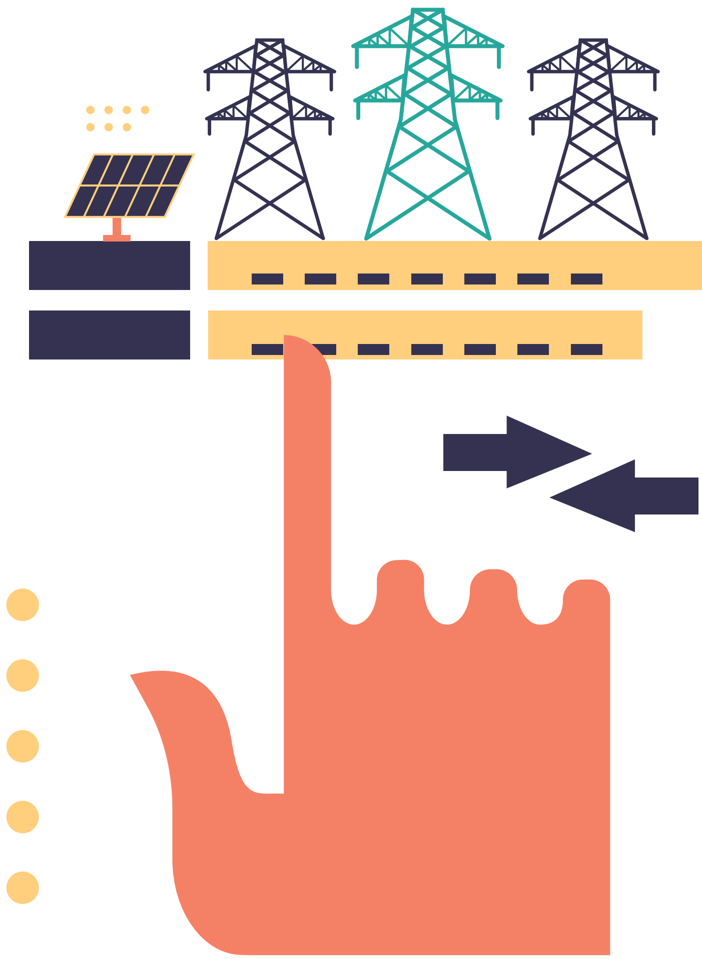
Lawson noted that transmission projects that bring less expensive renewable energy to the load where it is needed, such as GBX, should be a popular priority and a key part of utility plans, but he cautioned that they can easily become bogged down. Landowners have become more litigious and vocal about protecting their property, thus making the approval process more complex.

More broadly, he said, RTO-level analysis and approval, while valuable, is generally cumbersome for transmission projects.

"If you go back to the pre-RTO period, everything was done by utilities and coordinated by utilities. It is important that it has been somewhat consolidated over a broader region, but that creates its own problems," said Kincheloe.

"AS RENEWABLE PENETRATION INCREASES, THE COMPLEXITY OF INTEGRATING THESE RESOURCES INTO OUR SYSTEM ACCELERATES RAPIDLY."

AUBREY JOHNSON
EXECUTIVE DIRECTOR OF SYSTEMS PLANNING AND COMPETITIVE TRANSMISSION
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR



For example, he noted that in Missouri, the ideal pathways to connect generation with load might cross between the territories for Southwest Power Pool and MISO and other parts of the state that are outside of either RTO. This means planning involves more parties and a greater and more diverse band of investors and players.

He added that the big spike in wind energy production has changed plans dramatically and rapidly but adds a new complication, because of its variability.

"More traditional generation near the load is being replaced by distant renewable resources. But you still need to have traditional sources available, and that also is a complication and a cost factor," he said.

WEIGHING THE NEEDS

A 2014 white paper by Navigant Consulting for the Department of Energy described in detail how transmission planning has changed and discussed the potential benefits to be weighed by system planners.

"In an RTO region, with multiple parties owning generation, transmission, and serving load, the RTO planning process now assesses the impacts of forecasted firm loads, existing generation and transmission assets, and anticipated new generation and transmission facilities to integrate transmission options with generation and demand response projects," the report said.

The report emphasized several benefits to having "expanded access" to a variety of generating sources, made possible through transmission projects, such as:

- Diverse sources for improved reliability
- Options for lower cost power
- Mitigating the economic ramifications of environmental regulation
- Fostering state renewable or clean energy policies

The report also touched on how system planners should consider to what extent technologies such as distributed generation and microgrids already offer such benefits to a certain area.

Changes in the industry, such as distributed generation and electrification, will play an increased role in transmission planning and needs in the future.

"MISO considers electrification as an elemental part of developing what we refer to as our 'futures,'" Johnson said. "We perform long-range planning using bookends of what we think the future will hold in terms of energy demand, generation mix, and other variables. Those bookends are plausible insights into the next 20-40 years for determining potential transmission development, and this is part of it."

Areas outside of an RTO's footprint generally conduct this planning through an integrated resource planning process.

A FOUNDATION FOR THE FUTURE

Changes may occur to assist with planning, such as new software that is more effective and better at cost analysis with the complex set of variables, and the variable costs and availability of resources.

The DOE white paper said such transmission planning applications will likely account for the uncertainty associated with generating unit and transmission system performance, weather-related demand volatility, resource intermittency, economic growth, fuel prices and public policies.

In the spring, MISO released its second MISO Forward report, which outlined changes in transmission and suggested a plan for how utilities might weigh and value various benefits of transmission.

Johnson noted that one of four "strategic imperatives" spelled out in the report involves "updating the investment approach for transmission by building off the value identified in new market constructs and reliability criteria to improve deliverability of key grid needs." The report also said MISO will strive to "enhance communication and coordination across the transmission and distribution interface — to address today's challenges with load modifying resources and with an eye toward emerging tech and active demand."

Johnson noted that communications with all parties will be critical, particularly about costs. "It is vitally important to the success of long-term transmission planning to have stakeholder buy-in to the issues, needs and process. Equally important and a common roadblock will be cost allocation — or simply put, who will pay for the transmission development that may ensue."

Communications horizontally among regional bodies must also be addressed, he said.

"While collaboration with our neighbors has always existed, improvements are always being sought. The complexities and issues we face cannot be considered in a vacuum."

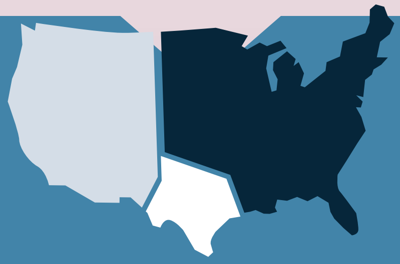
WHAT IS TRANSMISSION?

Between the power plants, dams, and facilities that generate electricity and the wires that connect your home and your neighbors to substations in your community is a series of high-voltage wires and towers that make up the transmission system.

There are about

360,000

miles of transmission lines in the United States



Although it is collectively called one "grid," there are three independently operated sections of this system, called interconnections: Eastern, Western, and the Electric Reliability Council of Texas.

Sources: "United States Electricity Industry Primer." U.S. Department of Energy. July 2015. https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf"

"Annual Energy Outlook 2020, Electricity." U.S. Energy Information Administration. January 2020. https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Electricity.pdf

The power running through the lines in each interconnection is managed by

66 balancing authorities

– entities that keep a close eye on matching the power supply and electric demand.

Seven

of these authorities are regional transmission organizations (also called independent system operators) – and manage the supply and demand for approximately

2/3

of people in the US.

These organizations collectively manage more than

310,000 miles

of transmission lines.

Electric utilities, including public power utilities, split the cost of transmission across the group of users.

For every kilowatt hour you use, about

1.35 cents

pays for the transmission of that power. In 2019,

13%

of the average customer's electric bill went toward transmission.

The cost of transmission is expected to continue to rise over the next few decades, increasing to almost

16%

of the average bill by

2040

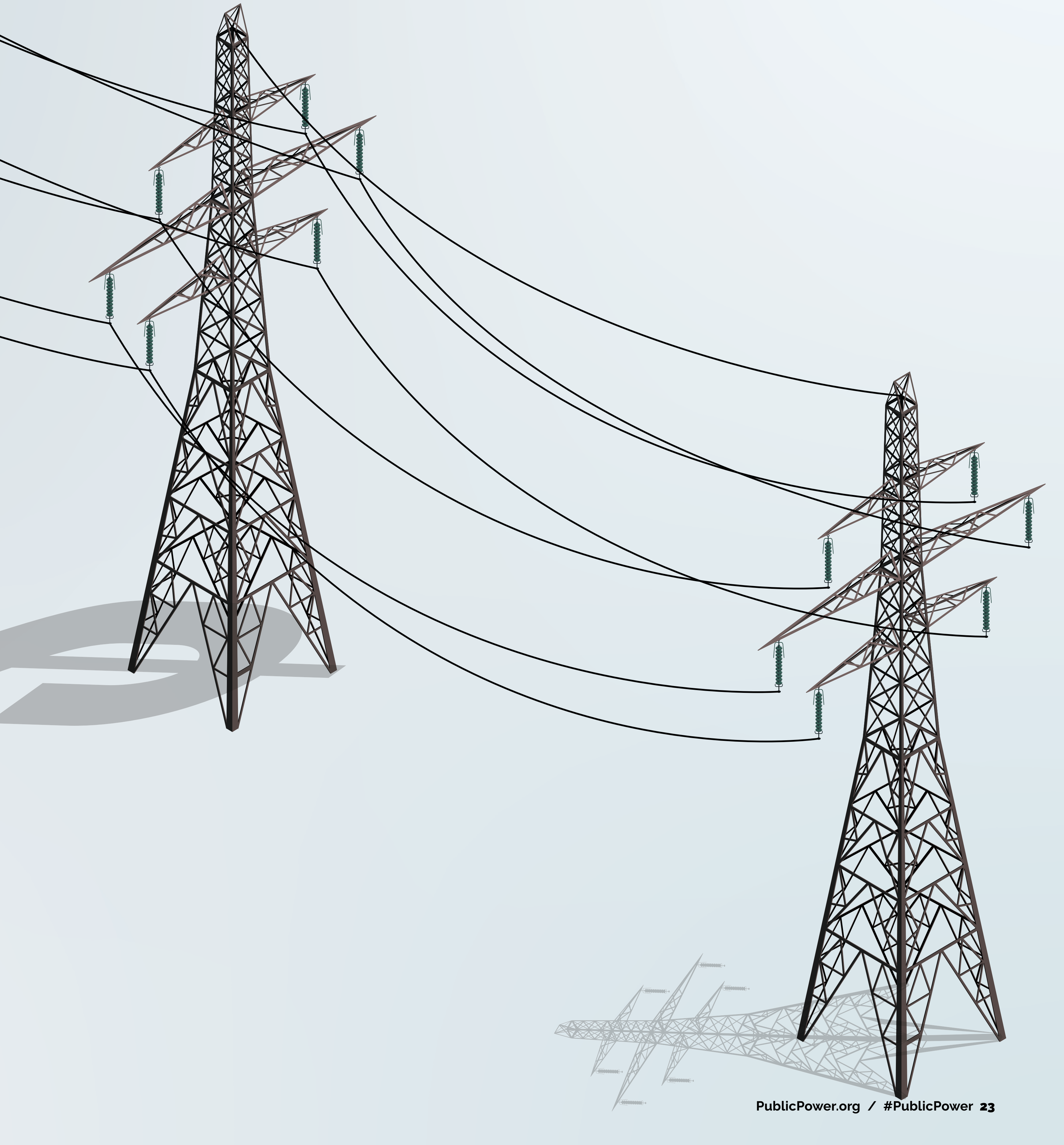
This increased cost will largely offset expected declines in the cost to generate energy.

Customer advocates, including public power, are working to ensure transmission costs are fairly split and don't get too high. As such, new projects should:

- Relieve congestion
- Benefit customers (e.g., connect to lower cost or preferred sources of generation)
- Be planned in coordination with the region, to reduce development of unneeded capacity or curtailments
- Support greater reliability

CHALLENGING COSTS: PUBLIC POWER HEDGES TRANSMISSION EXPENSES

BY SUSAN PARTAIN, SENIOR EDITOR
AND CONTENT STRATEGIST
AMERICAN PUBLIC POWER ASSOCIATION



Energy prices might be going down, but public power utilities — and customers — are seeing transmission costs go up and are facing policies and regulations that might lead to further increases.

RISING COSTS

Randy Howard, general manager of the Northern California Power Agency, a joint powers agency serving 16 public power utilities in California, said that transmission costs are the fastest growing component of members' and customers' bills. Over the past decade, NCPA members have seen transmission costs increase more than 10% per year. In real terms, Howard said that means some California customers have seen transmission costs go up from about 8%-12% of their bill to about 25%-30% of their bill.

Customers in Oklahoma have also seen transmission costs become the fastest-growing component of their bill, said Dave Osburn, general manager of the Oklahoma Municipal Power Authority. He estimated that the joint action agency has seen average annual increases of about 9%-10% per year since 2012. For OMPA, Osburn said, that amounts to about $12 million per year in new transmission expenses, and it has not seen an equivalent offset from decreased energy costs.

"That has certainly got our attention, because over that same period, we have seen virtually no load growth, because of energy efficiency programs and natural improvements in energy efficiency," said Osburn.

In Missouri, Jeff Knottek, director of transmission planning and compliance at City Utilities of Springfield, also reported an average increase in transmission costs of about 10% per year for the last seven years, although he expects those increases to level off for the next several years.

FACTORS AFFECTING COSTS

Osburn and Knottek both pointed to the robust transmission build-out that has occurred in the Southwest Power Pool, to which both entities belong, which has totaled about $10 billion in expansion costs in recent years.

Osburn said the buildouts have allowed for a vast amount of wind power to move around the region, have relieved congestion, and have supported some of SPP's economic projects.

Tom Kent, president and CEO of the Nebraska Public Power District, described the cyclical nature of transmission development, where the system expands to support increased load, improvements need to be made, and then capacity grows to the point where system capabilities need to expand again.

NPPD is the largest transmission owner and operator in Nebraska, overseeing more than 5,000 circuit miles. Kent said that NPPD is in an expansion phase with its transmission system, most of which has been done under SPP's transmission planning and expansion process. He estimated that about $750 million in recent transmission system investments has gone toward new facilities.

"Utilities located in western wind-rich areas, where many of the transmission upgrades have occurred, generally experience more benefits than utilities located along the eastern edge of the footprint," said Knottek.

Knottek said that City Utilities faces high congestion costs and higher locational marginal prices. He estimated that City Utilities pays about $5 per megawatt-hour more than the average SPP transmission customer, and almost $10/MWh more than some members in the western part of SPP.

"We've been on the short end of the stick of the transmission buildout," said Knottek, who explained how the costs have compounded. "We're paying for these assets over 40 years. Annual new construction projects get added to your prior year, so the total end cost continues to grow and multiply; it keeps going up each year."

In California, Howard pointed to the uptick in wildfires as contributing to added transmission costs in a number of ways.

"One in 10 wildfires are started by power lines, but 10 out of 10 are damaging our infrastructure," he said. The cost to replace and recover these assets has been expensive, and he estimated that wildfire insurance costs have also gone up about 500% over the past few years. On the operations side, NCPA members also have implemented enhanced vegetation management efforts, which Howard said have doubled or sometimes tripled those costs. Members have also taken a hit when the public safety power shutoffs have occurred at the transmission level, cutting off entire communities.

"While we have taken a number of measures to try to mitigate costs occurring year after year, the expectation is that we will see transmission cost adders of 15%-25% increases per year for the next few years due to wildfires," he said.

MITIGATING COSTS

Howard said that most of his members are principally dependent on transmission assets owned by Pacific Gas and Electric. As such, the investor-owned utility's transmission cost structure has a major impact on the public power utilities' rates.

Howard believes that IOUs have turned to transmission as a key component of gaining a rate of return on investments, especially since many have divested from generating assets and instead rely on power purchase agreements that don't offer a rate of return.

"We see what appears to be gold plating and a transfer of capital structure to transmission — probably more so than necessary," he explained.

In 2016, NCPA made a claim with the Federal Energy Regulatory Commission in regard to about $1.8 billion of annual capital expenditures that do not go through any stakeholder process. Although the initial claim did not turn out favorably for NCPA, an appeal to include NCPA members as part of a stakeholder process over transmission expenses received a favorable decision. However, due to backlogs at FERC, Howard said that there are currently three outstanding rate proceedings (NCPA has since made the same case in subsequent years), which have yet to be approved.

"The underlying goal is to ensure that everyone who is using the system is paying their fair and appropriate share of costs"

TOM KENT
PRESIDENT AND CEO
NEBRASKA PUBLIC POWER DISTRICT

"It's quite frustrating that with these rate cases, they have been able to collect the rates, even though we have shown that they aren't prudent rates, there are over-collections and our members are due these refunds," said Howard. "It is quite problematic, because it gives an incentive for a transmission owner to seek more than they know they are going to get, just because they have the ability to derive the revenue for several years before they have to give some of it back."

Howard said that NCPA members are due several hundred million dollars in refunds if FERC approves the rate case settlements, which, given PG&E's current status, means that they might have to pursue the funds through a bankruptcy proceeding, adding another layer of complication.

Osburn said that OMPA has been "pretty aggressive" in finding ways to offset rising transmission costs. OMPA filed a complaint with FERC to lower the return on equity, which was successful in lowering some of its transmission costs. He said that it is helpful to be able to challenge the high rates of return that transmission owners receive, which he said can be about 10%-12%. Economic effects from the Tax Cuts and Jobs Act of 2017 also helped to slightly lower OMPA's transmission costs, according to Osburn.

"We're not always successful, but it helps to be engaged," said Osburn. "A lot of it gets down to the transmission planning models used, and what assumptions are used. Try to get input on those assumptions."

He said that having staff engaged or working through a joint action agency or at the national level is important, particularly if there are any committees or working groups that focus on cost allocation.

OMPA has also implemented robust energy efficiency programs, which Osburn said has helped to lower its peak by anywhere from 12 megawatts to 18 MW.

Despite the costs City Utilities has seen from transmission expansion over the past decade, Knottek said the utility continues to push for further builds along SPP's eastern seam as a way to relieve congestion and increase customer benefits. "The way you can do that is by building additional lines or increasing the ratings of facilities," he said. "Obviously, there's a cost to do that, but part of the beauty of being in an RTO is that you'll have 18 or 19 other transmission owners that are also contributing. You don't have to bear all of the cost of trying to build the transmission and plan it all."

COST ALLOCATION

"The underlying goal is to ensure that everyone who is using the system is paying their fair and appropriate share of costs," said Kent. "The challenge can come from the different view of the same coin."

In 2019, Kent led an effort among SPP members called the "holistic integrated tariff team," which examined SPP's transmission planning process and cost allocation, as well as other issues. He noted that the team provided SPP with several recommendations on cost allocation.

In SPP, members are divided into pricing zones, and costs are allocated on a license plate basis within each zone.

"As new entities come into those pricing zones or as zones change, sometimes you can get unintended cost shifts that can be problematic," Kent said. He mentioned that the holistic tariff team made some recommendations for how SPP could ensure that changes to pricing zones were more equitable.

"The rules may be slightly different from region to region, but the underlying fundamentals are very similar — to put the costs on who is benefitting from the expansion," said Kent. "For new generation, if the developer wants to build, and if a study determines that transmission needs to be upgraded to reliably support that generation, then the beneficiary is the generation developer, so they are tasked with the cost."

REFORMING FERC ORDER 1000

FERC issued Order No. 1000 in July 2011 with the intent of improving transmission planning, including expanding opportunities for competitive transmission developers and increasing interregional planning. However, several analyses have shown that the order is not working as intended, with many projects still being developed outside of the regional planning process, and relatively few projects open to competition. In addition to these concerns, some supporters of renewables and distributed energy don't believe Order No. 1000 has done enough to spur transmission development. As such, several members of Congress have introduced bills to require FERC to reform the order or to require the Department of Energy to study the interregional transmission planning process.

CHANGING LANDSCAPE

"We built generation so that we didn't really rely on others to provide our resources, but it seems that those days are long gone," said Knottek. "It is cost prohibitive. You need to take advantage of a pool where you have more access to a diverse mixture of resources."

OMPA explored the possibility of building its own transmission assets but found that the rules, which Osburn said have been established in large part by major transmission owners, have made the effort difficult.

When it comes to transmission development, "there's sort of a double standard," said Osburn, who explained that there doesn't seem to be uniform criteria for when projects get built for reliability purposes, and when costs can be shared. He also noted the risk of developing assets that might become stranded due to increased development of distributed generation.

"If more and more load is going to be served at the local level, who is going to pay for the transmission system?" asked Osburn.

He brought up FERC's recent notice of proposed rulemaking regarding transmission incentives, which suggests increases to incentives for transmission owners to build.

"We're very concerned by that — you don't need to incentivize folks to build more transmission or to gold-plate it," said Osburn, who noted that such a move would further increase transmission expenses.

"I personally don't see a lot of need for incentives for a transmission owner to be in an RTO/ISO or a lot of need for incentives to build new transmission," said Howard. "Where incentives are needed is with transmission owners to optimize the utilization factor of their transmission assets."

"If we can have more megawatt-hours flowing over the lines during more hours of the day, we could reduce the cost and provide benefit to our end use customers directly in doing so," added Howard.

STAYING ENGAGED

"It's rarely just one issue that drives the need to expand transmission," said Kent. "Usually, you have a combination of economic benefits or reduced congestion, as well as reliability benefits or some other quality benefit, such as more renewable generation that could be added."

Knottek described the cost-benefit analysis of transmission projects as subjective and noted that societal or environmental benefits, such as gaining access to more clean energy, can be weighed differently from community to community.

Kent agreed that evaluating costs and benefits of transmission builds is complex and nuanced, which is why, he said, it is important for utilities to actively participate in the process. "At the end of the day, the just and reasonable standard has gray in it."

He added that the planning process is helpful in identifying the economic value of projects and the cost-benefit ratio to system users, and that having a planning process helps ensure regional transmission organization funds are being used appropriately to benefit the consumers of the area.

Kent acknowledged that NPPD is a large public power utility, and therefore has the ability to be more engaged within the RTO. He advised that smaller utilities voice their concerns through a state association or joint action agency that can give the issue attention and represent any concerns about transmission costs or planning.

Knottek echoed that many complaints stem from those who do not have a role in transmission planning. "If you are small, you might not have the wherewithal to build transmission or generation; there's a real benefit to being part of an RTO."

To stay engaged with a lot of the activity happening at the regional or national levels, Howard said that NCPA is part of the Transmission Access Policy Study group and is an active member of the American Public Power Association. He noted that he'd like to see more involvement by other joint action agencies in the proceedings, and he commended APPA for its efforts to bring various public power parties together and get in front of the Commission.

"Our voice needs to be heard; we need to be at the table. And many times at FERC, we're not well represented on these cases," said Howard. "FERC proceedings are complicated and expensive, and the extent to which we can join in with TAPS or APPA is critical."

"We have to tell these stories and to talk about these costs," said Osburn. "Not all of these investments come through RTOs. Quite often, they are built by the transmission owner with no oversight, no rate case."

> **"Our voice needs to be heard; we need to be at the table."**
>
> **RANDY HOWARD**
> GENERAL MANAGER
> NORTHERN CALIFORNIA POWER AGENCY

Rethinking the markets' role in reliability

BY ELISE CAPLAN, DIRECTOR, ELECTRIC MARKET ANALYSIS, AMERICAN PUBLIC POWER ASSOCIATION

As our electricity generation mix continues to transform — with more wind, solar, natural gas, energy storage, and distributed energy resources, and less coal and nuclear capacity — the regional transmission operators and independent system operators are facing new challenges in ensuring that the markets support reliability.

These challenges include:

- Uncertainty about the real-time availability of renewable resources, given the variability of weather and limited dispatchability of these resources (other than hydropower).
- Ensuring sufficient flexible resources are in operation that can quickly ramp up and down.
- Difficulties in meeting frequency regulation and voltage support requirements.
- Increased risk of oversupply.
- Limited visibility of distributed energy resources (primarily rooftop solar) and their impact on patterns of electricity demand.
- Concerns stemming from an increased reliance on natural gas-fired generation, including pipeline constraints, merchant generators' reluctance to sign firm contracts for natural gas delivery, and environmental limitations of natural gas generators to switch to oil when supply is constrained.

It is becoming increasingly apparent that the long-standing measure of reliability — a sufficient supply of megawatts to meet the projected summer peak demand plus a reserve margin — may no longer be appropriate. What's needed instead are operational capabilities and attributes such as ramping (up and down), fast start, frequency regulation and voltage support.

To address these new challenges, the RTOs/ISOs have implemented or proposed the following changes to the markets they operate, and they are evaluating other options:

- Removing barriers to the participation of energy storage resources, in compliance with the Federal Energy Regulatory Commission's Order 841 (All RTOs except ERCOT must comply with this order).
- Establishing a ramping product to ensure that resources capable of ramping up and down are available when needed.
- Determining a more accurate capacity value of renewable resources based on how much of each resource is on the grid.
- Creating new day-ahead market products to ensure that there are sufficient resources to meet unexpected changes in generation and load between the day-ahead and real-time markets.
- Considering multiday markets to increase the visibility of resource needs beyond the day-ahead market.
- Revising shortage pricing rules, which allow energy prices to spike to high levels during shortfalls in reserves, to provide stronger financial incentives for the development of flexible, fast ramping resources.
- Considering having seasonal reliability requirements rather than only meeting summer peak load.
- Operating an energy imbalance market to allow trading of energy imbalances over a wider geographic area, which provides access to a more diverse array of resources.
- Allowing distributed resources to participate.
- Requiring certain wind and solar resources to be dispatchable.

RTO/ISO market changes

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Establishing a ramping product	●			●	■		▲
Recalculating the capacity value of renewable resources	■				●	■	■
New day-ahead market products	■		▲				■
Multiday energy and ancillary services markets			■				■
Revising shortage pricing rules		●		■	■	●	
Seasonal reliability requirements			■	■			
Operating an energy imbalance market	●						▲
Allowing DER participation	●	■				●	
Requiring wind resources to be dispatchable				●	●		●
Requiring solar resources to be dispatchable				●	■		●

● = implemented/approved by FERC ▲ = proposed to FERC ■ = being discussed/evaluated

Customer advocates, including public power, have expressed concern that some of these market rule changes might significantly increase costs beyond what is needed to address the identified challenges.

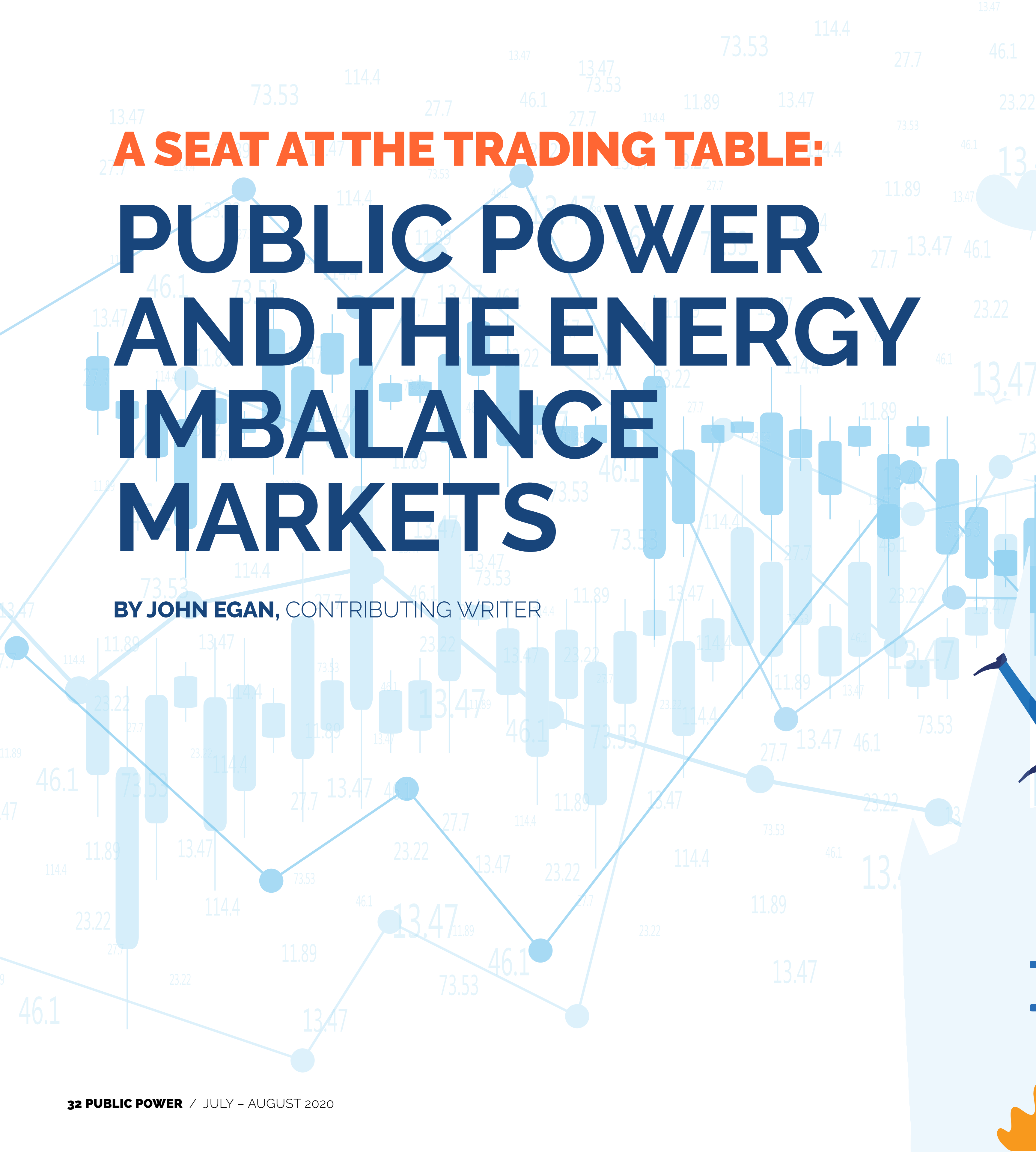
Two such examples are:

- Despite stakeholder opposition, FERC approved changes to PJM Interconnection's reserve markets in May 2020 that would greatly increase energy and reserve prices. One of PJM's justifications for these market rule changes was that they address the uncertainty created by higher levels of intermittent renewable resources. The PJM market monitor and customer representatives, including public power, disagreed and countered that PJM had failed to justify the need for such increases in prices.
- In April 2020, ISO-New England proposed creating new option products in the day-ahead market to ensure the real-time availability of energy in the event that resources are not sufficient to meet demand, especially during extreme cold weather. The ISO explained that since its system relies on natural gas and renewable resources, it faces an increased risk of these resources not being available. Filed without stakeholder support, this proposal elicited opposition from the states, public power, and other customer representatives for imposing higher costs beyond the need to ensure reliability.

The RTO/ISO-operated markets provide opportunities to procure the operational characteristics and attributes needed to ensure reliability in a rapidly changing electricity industry. However, FERC should ensure that these rule changes focus on meeting these challenges without imposing excess costs on consumers.

A SEAT AT THE TRADING TABLE:

PUBLIC POWER AND THE ENERGY IMBALANCE MARKETS



BY JOHN EGAN, CONTRIBUTING WRITER

The emergence of energy imbalance markets, and their ability to bring a variety of benefits to public power utilities, is a sign of strategic change in the electricity business.

The public power entities that have moved to join or have already begun participation in these markets have determined that the projected benefits outweigh the costs and recognize how these marketplaces can support other goals.

INTRODUCING THE EIMS

Energy imbalance markets provide a platform for participants to voluntarily trade surpluses or deficits in generation in real-time. If there's a gap between generation and demand, that energy is traded in the EIM, typically on a five-minute or 15-minute basis.

The California Independent System Operator's Western Energy Imbalance Market was launched in 2014. Its current and future participants represent about 82% of the load in nine states: Arizona, California, Colorado, Idaho, Montana, Nevada, Oregon, Utah, and Washington.

Public power utilities including the Sacramento Municipal Utility District in California (as part of the Balancing Authority of Northern

California), Salt River Project in Arizona, and Seattle City Light in Washington have begun participating in the WEIM. Other public power entities, including Colorado Springs Utilities, the Los Angeles Department of Water and Power, Platte River Power Authority, Turlock Irrigation District, and Tacoma Public Utilities, are scheduled to join the CAISO WEIM in the next few years. A second phase of BANC's participation will include the Modesto Irrigation District, the City of Redding, the City of Roseville, and WAPA-Sierra Nevada Region.

The Southwest Power Pool's Western Energy Imbalance Service is scheduled to launch in early 2021, pending approval by the Federal Energy Regulatory Commission. Public power entities planning to join SPP's service include the Municipal Energy Agency of Nebraska and the Wyoming Municipal Power Agency.

Participation in an EIM does not require membership in the larger organizations that operate those real-time markets, but it does require signing an agreement with either the CAISO or SPP.

COST SAVINGS

Since its founding, CAISO estimates that participants have received $920 million in cumulative gross benefits, mainly through providing them with access to lower-cost energy.

"We estimate that our first year of participating in the WEIM generated about $7.1 million of net benefits, which is about 71% more than we originally projected," said Jim Shetler, general manager of BANC, which joined the WEIM in April 2019 on behalf of SMUD, one of its members.

BANC and SMUD thought it would take about two years to recover their outlays needed for BANC's participation in the WEIM, but better-than-expected benefits in their first year of participation have shortened the payback period.

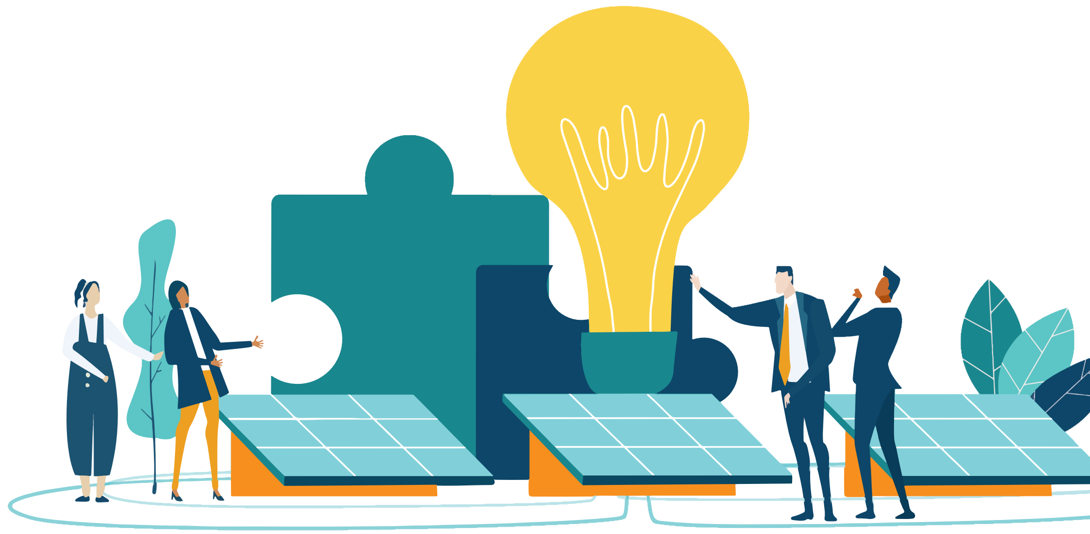
BANC and SMUD incurred about $8.9 million in first-year costs to participate in the WEIM, which included a $4.4 million fee for annual operating costs.

Shetler said most of the benefits derive from avoided costs, such as not turning on higher-cost generators to meet peak demand when lower-cost resources are available. In addition, BANC/SMUD also have had some incremental sales through the EIM.

SRP, which began participating in the WEIM in April 2020, thinks that participation will save the utility and its customers about $4.5 million per year, Sara McCoy, SRP's director of EIM implementation, said in an interview. In SRP's service area, where energy costs rise sharply during the broiling summer months, participating in the WEIM is an opportunity to purchase lower-cost energy elsewhere.

"We incurred more than $20 million in implementation costs, and we're estimating $4.5 million of net benefits per year — or about a five-year payback," she said.

Colorado Springs Utilities, which serves about 235,000 electric customers in Colorado, expects to have first-time costs of between $100,000 and $300,000 to participate in CAI-



SO's WEIM, and the utility expects net annual benefits of between $500,000 and $1.5 million, according to its CEO, Aram Benyamin.

SPP hopes its WEIS can duplicate the success of a sibling wholesale market, the Integrated Marketplace, which SPP opened in 2014. The SPP estimates its Integrated Marketplace has saved participants over $3.5 billion since 2014.

MEAN, which provides wholesale power and related services to 69 utilities in four states (Nebraska, Colorado, Iowa, and Wyoming), expects to pay about $500,000 in first-year costs to participate in SPP's WEIS market, said Brad Hans, director of wholesale electric operations for MEAN.

CUTTING CARBON

Participating in an EIM can also help entities to achieve carbon-reduction goals.

Platte River Power Authority, situated in north-central Colorado, has a long-term generation plan that includes retiring a coal-fired unit and achieving a zero carbon energy mix by 2030. The plan to reach this goal relies in part on being able to join an EIM.

"Participation with the WEIM amounts to another significant step on the path to reach our 100% noncarbon energy goal," said Jason Frisbie, general manager and CEO of Platte River. "We determined that the WEIM provides the best opportunity to manage and access additional noncarbon resources while lowering our cost profile, which amounts to a win-win for our owner communities."

Steve Roalstad, communications and marketing manager for Platte River, explained that its location allows the joint action agency to interact with counterparts in the Western transmission interconnection, meaning it can take advantage of the wind generation east of the Rockies and the solar generation west of the Rockies.

"Wind and solar complement each other, and we can take advantage of different renewable resources," Roalstad continued. "For us, wind generation is plentiful in the morning, while solar output peaks in the afternoon, just when wind output is falling."

Platte River and Colorado Springs Utilities participate with investor-owned utilities Xcel Energy and Black Hills Electric Colorado in a joint dispatch agreement. The utilities hired a consultant to weigh the potential costs and benefits of joining either the WEIM or the SPP EIS market.

An analysis by The Brattle Group said joining CAISO's WEIM would save the utilities about $2 million per year.

"Participating in an energy imbalance market is a more economical solution, and in this business, it all comes down to economics," said Colorado Springs Utilities' Benyamin.

He added that while the cost savings were the most important reason to participate in the EIM, the decarbonization potential was also attractive. The utility's integrated resource plan calls for retiring the use of coal-fired generation and cutting its carbon emissions 80% by 2030 compared to 2005 levels.

"The industry is moving to a low-carbon future, and we don't intend to stand still," Benyamin said. "Participating in an EIM helps us complete our resource equation … It means we don't need to build additional peaking generation."

"If you have surplus low-cost generation," Hans said, "or if you have higher-cost generation that can be backed down in favor of lower-cost resources, you should definitely investigate participating in an EIM."

Participants said there's plenty of room at the table for other public power utilities, and that the benefits and costs of participating in an EIM scale with size.

"Smaller utilities will have smaller benefits," said Benyamin. "If you have some generation to contribute, even if it's only 5 megawatts, that is better than having no generation to contribute." Springs Utilities has about 1,000 MW of generation and a peak electric demand of about 965 MW.

"The benefits are directly proportional to how much generation and transmission you can commit to a market," added BANC's Shetler. He noted that utilities with less than 1,000 MW of generating capacity would have a harder time justifying stand-alone membership. "But if smaller utilities join together to form a larger virtual group, that could allow sharing of costs, which would make joining more cost effective."

That kind of group could be similar to the joint dispatch agreement between Platte River, Springs Utilities, Xcel Energy and Black Hills.

Utilities that can't commit generation to an EIM may still be able to participate if they have price-responsive dispatchable demand response programs, according to Mark Rothleder, vice president of market policy and performance at the CAISO.

"The EIM will facilitate demand response participation," said Rothleder. "We have had large industrial facilities participating in EIM that were dispatched based on their bids."

OTHER BENEFITS

All sources interviewed indicated they were happy with their respective EIM journeys so far. The public power utilities that only recently began participating — SRP and Seattle City Light — reported no negative experiences. Other public power utilities, whose participation is scheduled to begin in 2021 or 2022, said they were comfortable with the way their onboarding has progressed.

SRP's McCoy said there was another benefit from the EIM participation process: The journey was an opportunity for the organization to improve its processes and drive toward operational excellence.

Hans said MEAN joined SPP's EIS because it wanted a seat at the decision-maker's table.

"The governance structure of SPP's EIS was very appealing to us," Hans said. "Each participant will have a seat on the board. That's the way MEAN operates — each of our members has a seat on the organization's board. They may not make it to every meeting, but there's a seat for them if they do."

There's yet another reason for public power utilities to consider participating in these markets: the increased migration of entities to the CAISO WEIM has had the effect of removing potential intra-hour (i.e., five-minute or 15-minute) trading counterparties, and the same outcome will likely result as entities join the WEIS..

"The reality is that among entities that have not joined a real-time market like the WEIM or the WEIS, there are less potential trading counterparties," commented Shetler. "That's an important reason for public power utilities to participate in an organized real-time market."

HOMEWORK REQUIRED

The rules of the CAISO and SPP marketplaces are different, and in many cases, the devil's in the details. To better understand the costs, benefits and rules of each, prospective participants can talk to current participants — including other public power utilities, electric cooperatives and investor-owned utilities — or consider hiring a consultant that can quantify and detail the likely costs and benefits for that participant.

"Actively investigate the benefits and costs of participating in an EIM. Pay attention to details and timelines," said Hans. "Don't rush into it, but don't run away from it, either. Not participating in an energy imbalance market could mean your power costs stay level while others' are declining."

> **"Participating in an energy imbalance market is a more economical solution, and in this business, it all comes down to economics"**
>
> **ARAM BENYAMIN**
> CEO
> COLORADO SPRINGS UTILITIES

Understanding — and reimagining — financial transmission rights

BY ELISE CAPLAN, DIRECTOR, ELECTRIC MARKETS ANALYSIS, AMERICAN PUBLIC POWER ASSOCIATION

For many reasons, the cost to generate electricity varies from generator to generator.

People served through a regional transmission organization or independent system operator get the lowest cost generation available to meet the demand at a given time. But when demand in one area exceeds the capacity of the transmission system to deliver the least-cost power option, those customers receive electricity from higher-cost generation sources, which creates an additional "congestion cost."

Financial transmission rights and similar instruments (including congestion revenue rights, transmission congestion contracts, and transmission revenue rights) were created in the RTO/ISO markets so that load-serving entities (utilities and others responsible for providing power to end-use customers) can hedge such congestion costs. Because load-serving entities pay more for congestion than generators receive, FTRs are a mechanism to return this surplus payment.

Depending upon the RTO/ISO, FTRs are allocated directly to load-serving entities (with the remainder sold in an auction), sold only through auctions, or the load-serving entities get rights to the revenue from the auctions. The load-serving entities, generators, and financial institutions may all participate in the auctions.

FTRs have not consistently covered load-serving entities' congestion costs in all RTOs/ISOs. Recent data from the market monitors shows that:

- Over the past five years, the revenue offset in the PJM Interconnection has been between 50% and 104% of congestion costs.
- Midcontinent Independent System Operator FTRs covered 97% of congestion costs in 2019.
- Ratepayers in the California ISO paid about $900 million in excess congestion costs through 2019, although a series of changes to its congestion revenue rights market have reduced, but not eliminated, these ratepayer losses.
- Last year, FTRs were fully funded in ISO-New England, and load serving entities in Southwest Power Pool received more from their hedges than they paid in congestion.
- In the New York ISO, where all transmission congestion contracts are auctioned, owners of TCCs paid more than they received in revenue.

There are many reasons that congestion costs are not always fully recovered through these tools. One reason is that the FTRs do not always match the actual flows of power. A second and more significant concern is that auction prices are often lower than the value of the FTRs, allowing financial entities to purchase these instruments at a price below what they receive in congestion payments, creating a loss to load.

Another concern is how RTOs and ISOs manage credit and counterparty risk in all their markets, including the FTR market. The default of one financial trader in PJM, GreenHat, highlighted significant issues in how RTOs handled counterparty risk and the ineffectiveness of PJM's credit policy at the time. An independent investigation stated that financial participants highlighted the potential default years before it occurred.

A key question is whether such a complicated construct that allows financial entities to participate is truly the most efficient and effective means to hedge against congestion costs, or whether a new mechanism could be created to directly return the surplus costs to load-serving entities.

WHAT OTHERS ARE SAYING ABOUT FTRS

Here's what different groups have to say about FTRs and the participation of financial entities in them.

"[Such] trading is considered speculative because it is an attempt to profit by engaging in a risky financial transaction that isn't tied to any physical position in the ISO-NE marketplace. Speculative trading is permitted in FTR auctions because of the liquidity and competition it provides."

— ISO-New England's internal market monitor.

Most of the profits went to "financial entities that do not sell power or serve load in the ISO."

— CAISO market monitor

Financial traders' participation in the FTR markets "provides liquidity and competition, not just in the FTR market, but also in the broader energy market."

— Energy Trading Institute

"Traders are buying the hedges themselves because they are a profitable speculation. This is the exact opposite of what should prevail in a successful hedging market."

— John Parsons, economist, Massachusetts Institute of Technology, in a report on PJM's FTR

How has COVID-19 affected the electricity markets?

The Energy Information Administration projected a **6.5% decline** in retail sales of electricity to commercial and industrial customers and an expected 5% decline in generation in 2020 in its short-term energy outlook released April 2020. The decline in generation was expected to be most acute among fossil fuel plants.

In June, EIA further forecast that social distancing measures to limit the spread of COVID-19 would lead to the lowest summer demand since 2009.

Here are a few stats on how each region's load and demand changed, based on reports from the RTOs issued in May and June.

CAISO

3.7% average weekday load reduction, 1.4% weekend reduction since mid-March

Up to 6.7% reduction during weekday morning peak hours

$10/MWh decline in energy prices in the day-ahead and real-time markets when shelter-in-place orders were in effect

http://www.caiso.com/Documents/-COVID-19-Impacts-ISOLoadForecast-Presentation.pdf

ERCOT

2 – 3% lower peaks in early May

3 – 4% weekly decrease in energy use

6 – 10% reduction in early morning energy use

http://www.ercot.com/content/wcm/lists/200201/ERCOT_COVID-19_Analysis_FINAL.pdf

ISO-NE

2 – 4.4% decline in weekly load March through May

Biggest declines in late March, early May

https://www.iso-ne.com/markets-operations/system-forecast-status/estimated-impacts-of-covid-19-on-demand/

MISO

10.6% lower energy and load in May and 7% lower the first week of June

Greatest decline in load between 8 – 9 am

12% average load reduction March 14 – June 8

https://www.misoenergy.org/stakeholder-engagement/coronavirus-disease-covid19/

NYISO

Increase in residential energy use, especially midday

8 – 9% reduction in overall weekly energy use

15% reduction in the 7 AM hour, sharpest decline in New York City, which saw 20% reduction

https://www.nyiso.com/covid

PJM

10.4% decline in average weekday peak load since March 24

Up to 15% reduction in peaks in May

8% average reduction in energy

https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20200602/20200602-item-07-covid-19-impacts-and-load-forecast.ashx

SPP

7 – 10% reduction in load as of mid-May

5,000 MW reduction or more in hourly demand throughout April

https://spp.org/newsroom/covid-19/