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PUBLIC POWER MAGAZINE

AMERICAN PUBLIC POWER ASSOCIATION

SUPPLY AND DEMAND

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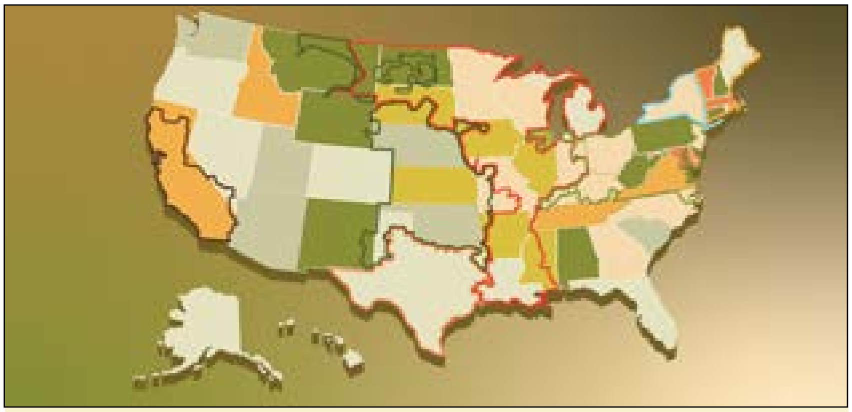

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The American Public Power Association is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We advocate before the federal government to protect the interests of the more than 49 million customers that 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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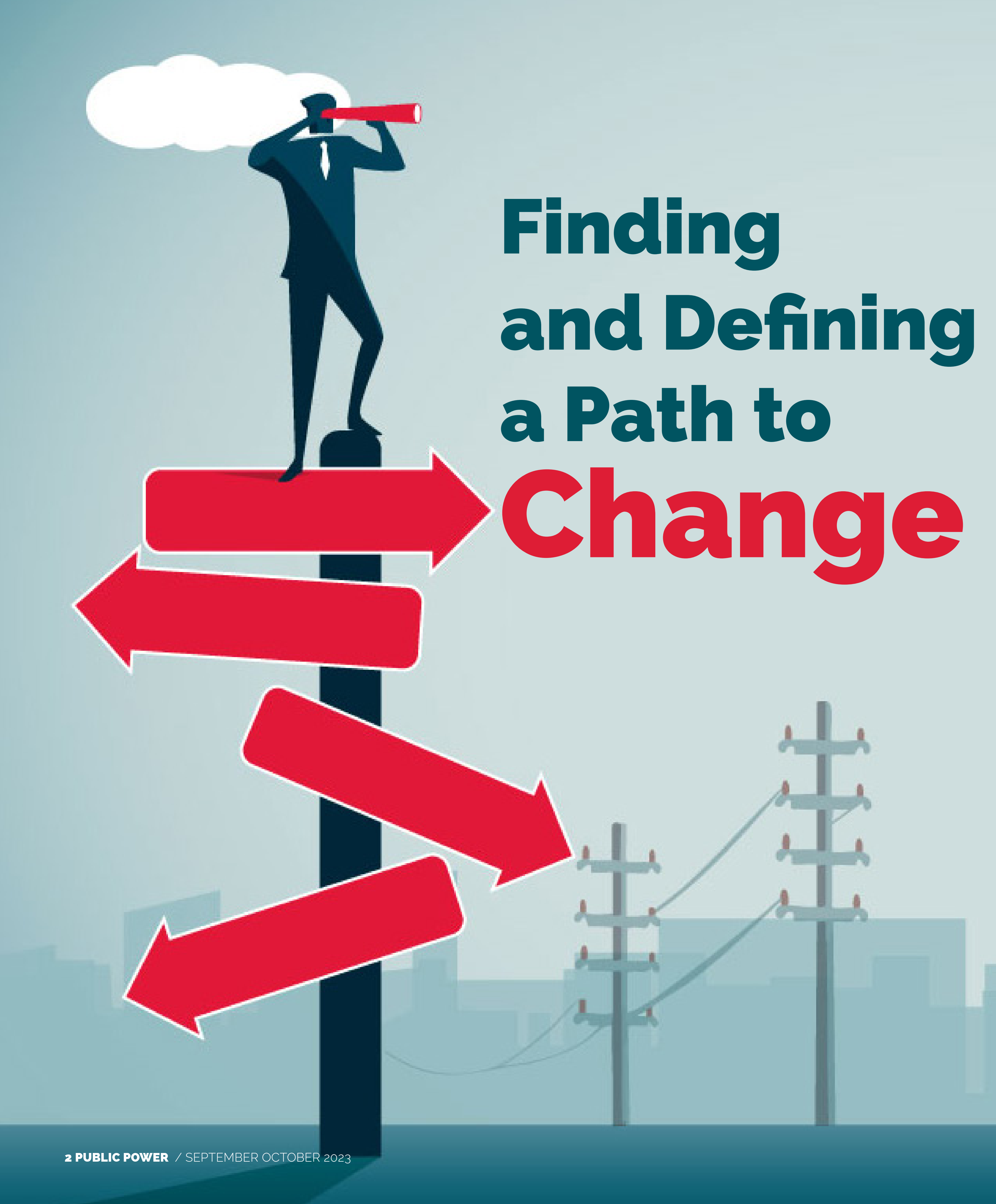
Finding and Defining a Path to Change



The electric grid is getting pushed to an ever-closer, fast transition to a "grid of the future." What exactly this future grid entails, however, remains open for interpretation. Whether that means a grid completely reliant on clean energy sources, or that is even more distributed and manages a high portion of variable, customer-sited resources; is prepared for significant new demand from electrification; or transformed to be hardened against extreme events. Whatever the vision, it is clear that how utilities will manage the electric supply and demand will change.

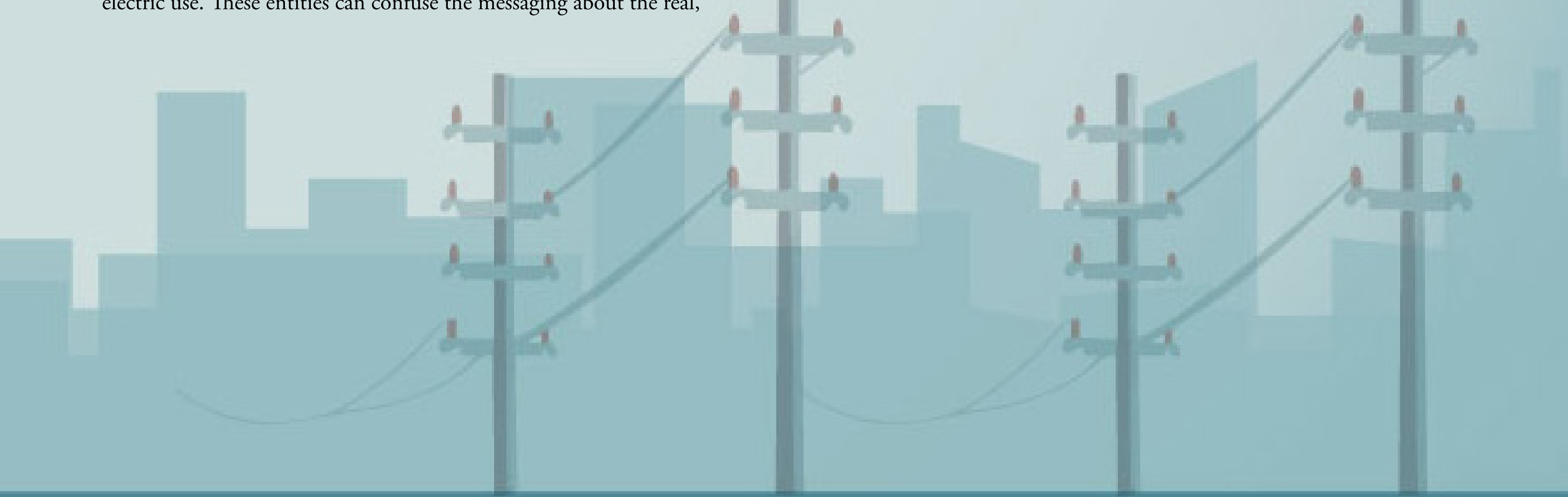
Utilities are where the rubber meets the road in adapting to the implications of these changes. For some, a changing supply has necessitated beginning to conduct or rethinking their approach to developing integrated resource plans (see page 4). For others, it will mean understanding how to derive the most benefit from energy storage (see page 32). We are at an intersection of being both indifferent to particular technologies and the key players to make decisions about which technologies to include in our all-of-the above strategies.

As the power supply is changing, the customer demand landscape is shifting in terms of what need they have for electricity and when, but also in their expectations in interacting with their utility. New players are entering the electricity market — whether the myriad solar developers or companies associated with home electrification — and might be presenting an alternate reality or expectation for your customers about their electric use. These entities can confuse the messaging about the real, practical challenges in shifting the electric supply (see page 36), which puts utilities on the defensive regarding why plan might not match with expectations.

The energy transition can be a flashpoint in community conversations, especially as the topic has become increasingly political. It is up to utilities to be responsive and offer their expertise, along with data and practical solutions, that recognize the varying interests across the community. As stakeholders with specific interests share their vision for what the grid of the future should be, the message from utilities should reflect where there is a common vision and where the viable paths are. For example, one proposed solution from some groups is that being able to harness more intermittent generation is a matter of building more transmission. Those in the electric sector know that the decisions about where to build new transmission — and how much it will actually contribute to helping better balance supply and demand — depends on a range of factors that change from year to year (see p 18).

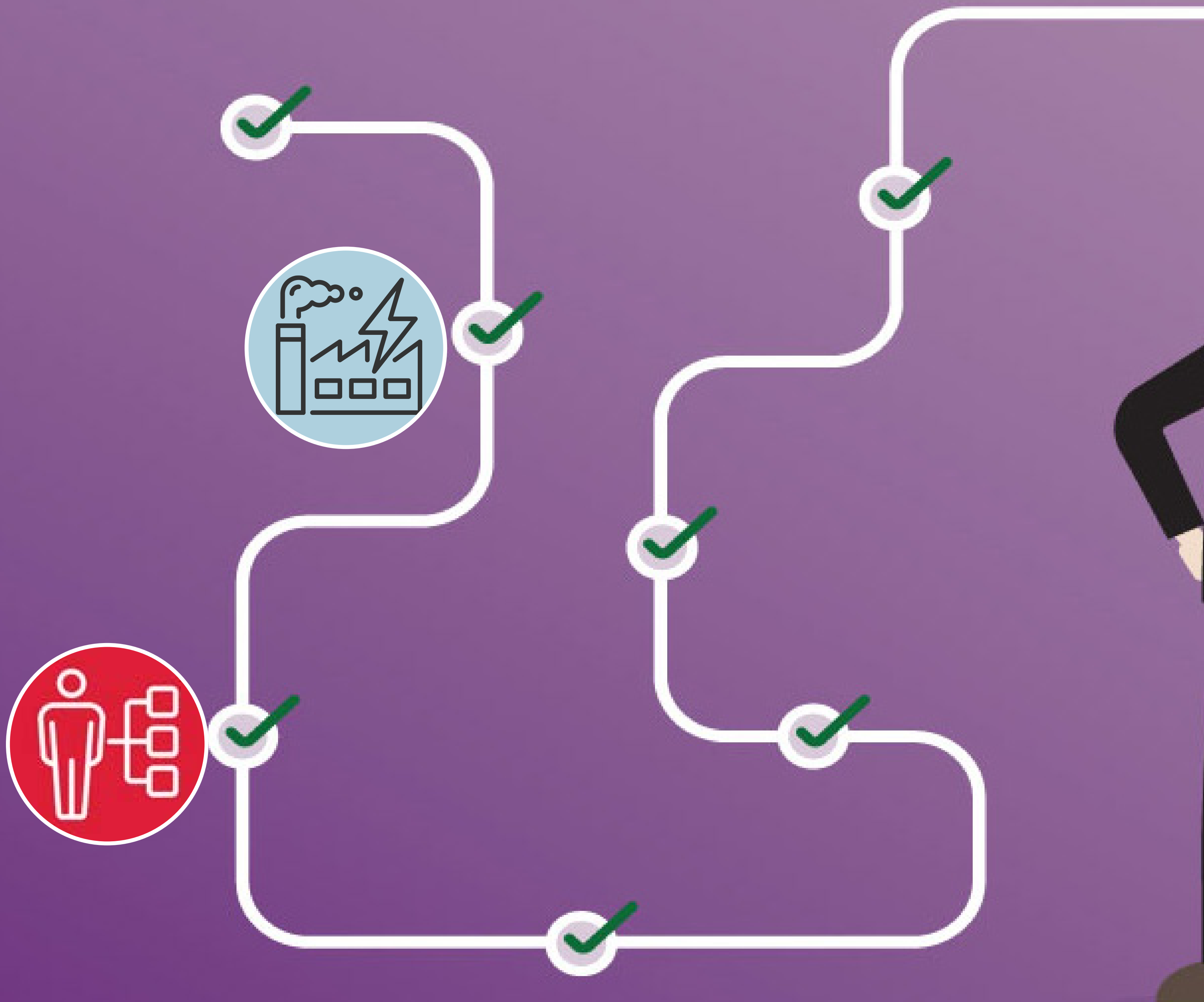
As utilities are in the middle of making sense of how to transition to a different energy mix, demand is rapidly changing as electrification picks up. Policies to transition to a cleaner energy mix are often on an aggressive timeline, yet electric vehicle sales have outpaced initial forecasts. While EVs often bring welcome new load, they hasten the need to understand the associated new usage patterns and what can effectively adjust customer behavior to avoid overloading transformers, which could compound the supply chain crisis (see page 30).

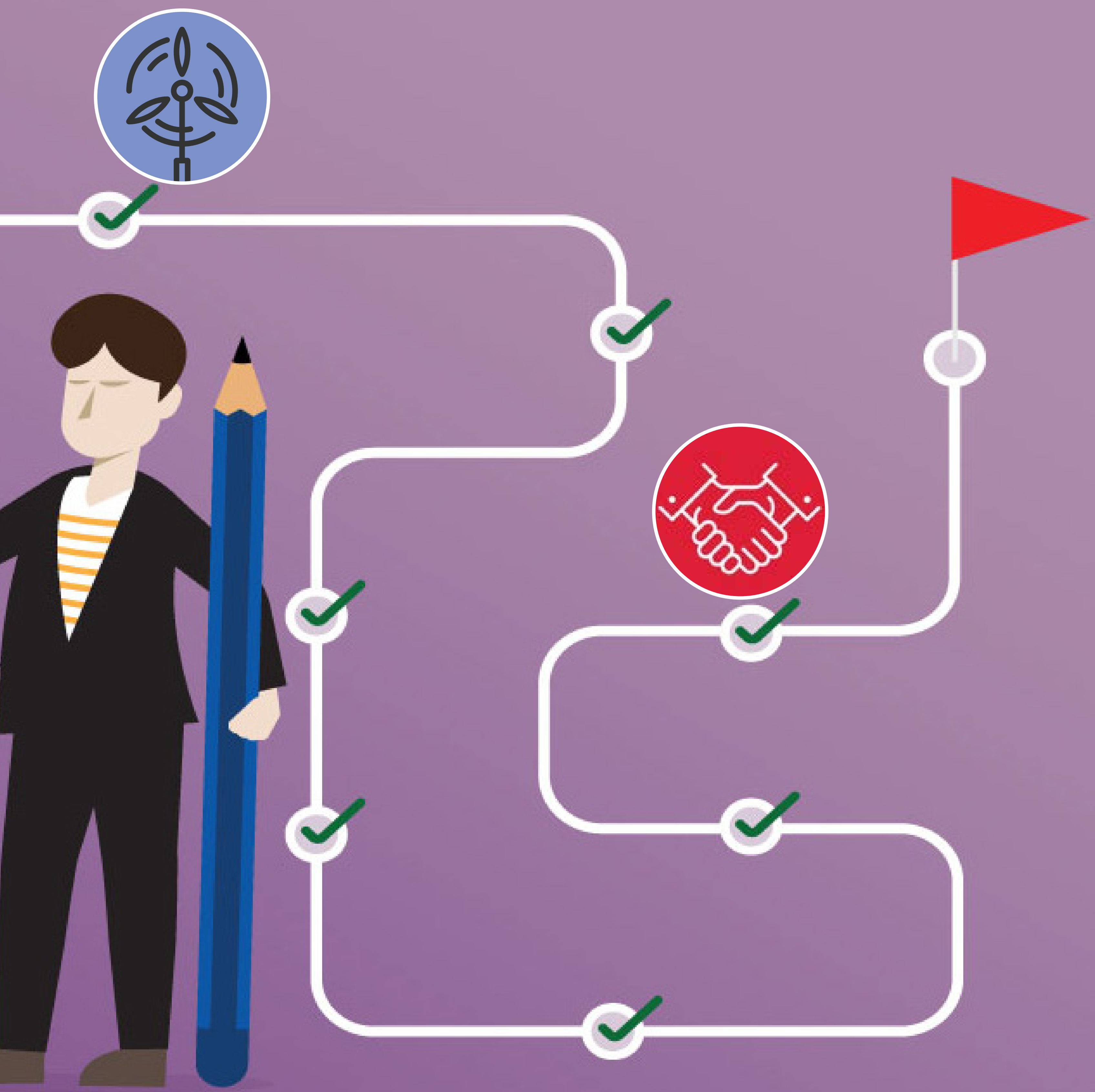
Although there are many challenges ahead, there are also many solutions and people looking to help. This issue of Public Power magazine aims to highlight the suite of issues and present how public power utilities are addressing and adapting to change.



INTEGRATED RESOURCE PLANS
ROADMAPS FOR A SHIFTING ENERGY LANDSCAPE

BY BETSY LOEFF, CONTRIBUTING WRITER





Ten years ago, some people in the utility sector were talking about a "death spiral" caused by shrinking revenues and flat demand. Now, some of the same voices are wondering how utilities will serve the coming loads from electrification while simultaneously increasing carbon-free generation in their portfolios. Things change, and an integrated resource plan, or IRP, can help a utility manage those changes. Here is a look at how three utilities are mapping out their plans for a shifting supply mix.

A New Pace

What exactly is an integrated resource plan? "It's a strategic plan to help us document our intended path for the next few years to meet our reliability, resiliency, financial and decarbonization goals," said Jackie Pratt, general manager at Stowe Electric Department, a Vermont public power utility serving nearly 4,450 residential and commercial customers.

Despite the common goal of defining in detail how a utility will maintain a reliable and affordable power supply, IRPs can vary in terms of frequency and implementation implications. In some cases, their production and frequency are dictated by state or local regulations.

"The biggest issue for me is prediction of energy use and how electrification impacts your system."

Jackie Pratt, general manager, Stowe Electric Department, Vermont

Stowe is required to produce an IRP for its state regulators every three years.

Sikeston, Missouri, doesn't have such a requirement, and 2023 is the first year the community-owned utility, which serves about 9,000 customers, has gone through the rigors of integrated resource planning. Utility staff are doing this because the city's 235-megawatt, coal-fired generation facility went into service in 1981. "It's 42 years old now, and we expected it to last 50 years, so it's time to start looking at what the future looks like," explained Rick Landers, Sikeston's general manager.

Staff members at Eugene Water and Electric Board in Oregon aren't new to the IRP process, but they've accelerated the cadence. EWEB, which serves about 96,000 customers, last went through the IRP process 10 years ago, but, moving forward, the utility plans to develop an IRP every two years, said spokesman Aaron Orlowski.

"It's a good practice, especially in today's environment, where the energy landscape is shifting so quickly," he said.

EWEB manages the IRP process in-house. Orlowski said the utility uses a consultant for some guidance, and the utility also runs Aurora energy forecasting software to evaluate resources in a 20-year planning horizon.

Sikeston is using a consulting firm that runs proprietary forecasting software. It's a firm well-known for working on IRPs. "There are many vendors and engineering firms that will do these studies, but some have only done one in the last five years," Landers noted. "You're best off using someone more active in doing IRP work for utilities."

Stowe is also getting a little consulting support, but the utility mostly follows a highly "prescriptive" format required by state regulators, according to Michael Lazorchak, regulatory compliance manager at Stowe. "We are expected to work with that framework, and that guidance comes from statutory language and PUC rules," he said.

Charting What Matters

Reliability is the No. 1 target for each of these utilities. In Vermont, cybersecurity and finance are also now among the items that must be addressed in an IRP. In any locale, the list of things to consider is a long one. In Sikeston, Landers said the utility is examining plant economics, environmental regulations, fuel availability, future costs, as well as market impacts from the regional transmission operator. He added that rate impacts are an essential factor in sourcing generation for the utility because it serves an economically challenged territory. "We have to balance affordability with the environmental issues," he said.

"When you're looking for a carbon-free solution, they haven't yet come up with a replacement for a coal plant that is reliable and low-cost, too. It may exist sometime in the future, but it doesn't exist now."

- Rick Landers, general manager, Sikeston Electric, Missouri

Landers said Sikeston is looking at more options for renewables, particularly since the elective payment tax credits, passed as part of the Inflation Reduction Act in 2022, have made ownership of these assets more economically viable for nonprofit utilities. "There have been tax incentives for carbon reduction for quite some time, but as a municipal utility, we're not a taxable entity, so we couldn't get a 20% to 30% credit for investing in or building a solar or wind facility," he explained.

Finding ways to incorporate a higher portion of renewable energy into the generation mix is critical in Eugene, where the utility has a requirement to be 95% carbon-free by 2030 and carbon neutral by 2050. (The utility's current mix is approximately 90% from carbon-free sources due to receiving a significant portion from hydropower.) In Vermont, utilities need to be 75% carbon-free only for larger resources, like hydropower, and utilities there have until 2032 to achieve this. By the same year, the state also requires 12% of the utility's retail sales to come from beneficial electrification programs, like getting heat pumps into customer homes and offering electric vehicle charging rates. "The renewable energy standard plays an outsize role in our power supply planning," Pratt said.

Forecasting Electrification

All three utilities have been very public with their IRP process. Press releases, town meetings, bill stuffers and social media are among the communication tools used. Stowe's team also decided to conduct a customer survey. The results showed that 13.5% of respondents were planning to install heat pumps in their residences and 42% were planning to purchase an EV, meaning electrification could boost demand soon.

This affects much more than generation resources. "The biggest issue for me is prediction of energy use and how electrification impacts your system," Pratt said. The adoption of EVs, heat pumps, rooftop solar and household battery energy storage prompts a host of questions, she added, and offered a few: "What should your rate structures look like? What should your system be engineered to handle? Where do you need to make upgrades?" She also noted that the IRP process will help the utility reexamine its rates.

Electrification is a huge driver for Eugene's coming load growth, too, Orlowski said. Between the incentives for EV adoption built into the Inflation Reduction Act and Oregon's ban on the sale of gas-powered vehicles beginning in 2035, utility management expects demand to grow by about 2% annually starting in 2030.

Along with that pressure, Eugene is affected by the Western Resource Adequacy Program. "It would require utilities to have a 15% buffer on their resources. If you think you need a certain amount of generation to meet peak demand, add 15%," Orlowski explained.

Serving that increasing load with hydropower may be more difficult in the future, too. While hydropower is a go-to clean resource in the Pacific Northwest, there are increasingly operational mandates passed down by state regulators and legislators hoping to protect fisheries. "That means there is less flexibility in how those facilities are used to generate electricity," Orlowski said.

Flexibility is crucial when you're adding variable generation to the mix. "When you're looking for a carbon-free solution, they haven't yet come up with a replacement for a coal plant that is reliable and low-cost, too," Landers said. "It may exist sometime in the future, but it doesn't exist now."

Eugene is seeing a similar issue. "There aren't many low-carbon resources that generate electricity on demand," Orlowski said. His utility team included small modular nuclear reactors, or SMRs, in its models because SMRs are expected to be commercially available in the early 2030s. Another resource the utility is considering is geothermal. "We did not include geothermal in this year's IRP because the traditional style is site-specific, so there wasn't good pricing data for it. There have been recent advances in the last couple of months for advanced geothermal, which promises to have more replicable abilities, so hopefully we can include pricing data for geothermal in our 2025 IRP."

Because SMR units can be combined to add generating capacity, they vary in size from 12 MW to hundreds of megawatts. Even with the pricing data available today, though, SMRs appeared promising for Eugene, which is a winter-peaking utility with a prolonged period of overcast skies when the cold sets in, so solar doesn't work well there.

In fact, the analytic model the utility used didn't even recommend solar power, but it did recommend demand response. This is in part due to a promising response earlier this year to reduce demand. When Eugene tried putting out a call for customers to conserve this summer, its 96,000 customers shed between 10 and 15 MW.

Ultimately, IRPs bring a variety of power management and generation ideas to the table. "To run the system, you need a resource mix that has different attributes. What I hope for our customers to learn from the IRP process is what makes sense and what doesn't," Landers said.

"One of the things people need to understand is that when it comes to renewables, there is no postage-stamp solution that works nationwide," he noted. "What works in Kansas may not be close to what works in Kentucky."

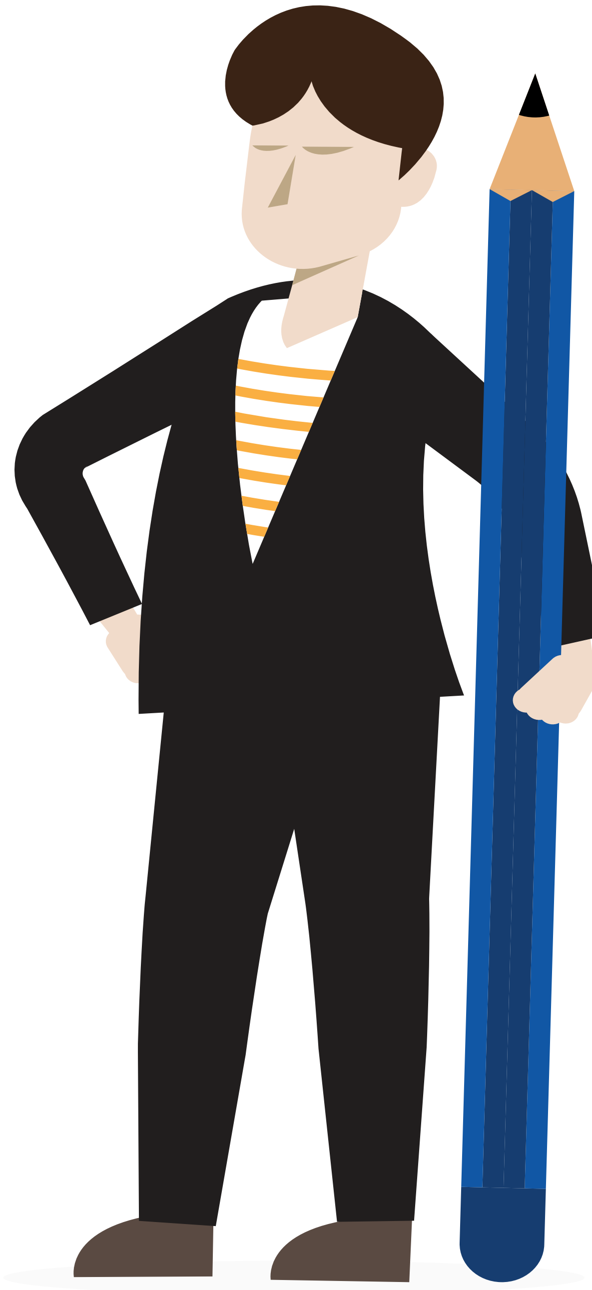
Orlowski said much the same thing, noting that renewables provide low-cost energy, storage can shift consumption patterns, and on-demand resources have an important place on the grid, too. "We're going to need that whole mix, and that's something we need to tell our customers because there is no easy solution to achieve this energy transformation," he noted.

"We're going to need that whole mix, and that's something we need to tell our customers because there is no easy solution to achieve this energy transformation."

- Aaron Orlowski, Eugene Water and Electric Board, Oregon

In addition to a lack of easy answers, there aren't likely to be exact answers, either.

"The Department of Public Services always says, 'There is no right or wrong answer. We just want to see that you're thinking these issues through, that you're giving a good-faith look at all the factors impacting the system,'" Stowe Electric's Lazorchak said. "They want us to think about the future, but they're not telling us which direction to take. They're leaving that up to the distribution utilities and our customers."



UTILITY IMPROVES WORKFLOWS, SAFETY, AND EQUIPMENT MAINTENANCE WITH THE HSI EHS PLATFORM

CONFIGURABILITY AND EASE-OF-USE CITED AS DETERMINING FACTORS FOR COMPANY-WIDE SUCCESS

When Joshua Reilly joined Pinal County Electrical District No. 3 (ED3) as Safety Specialist and Field Asset Inspector, he noticed the Arizona utility didn't have any consistency in capturing safety-related data, leaving them vulnerable to mistakes.

At ED3, each department had their own way of reporting inspections, incidents, near misses, and observations. Some departments used paper forms while others took freehand notes. At the end of the day, the information was transcribed into spreadsheets, a time-consuming process that introduced another opportunity for data entry errors. This manual entry also caused delays in reporting incidents and requesting equipment maintenance.

Because each department had unique needs, ED3 needed a robust, completely customizable system. To get buy-in, the system needed to be easy to use for everyone from field technicians and inspectors to upper-level managers. Reilly knew streamlining safety and maintenance processes would also increase efficiency. After an exhaustive search, ED3 chose HSI's EHS Platform due to its configurability and ease-of-use for even the least tech-savvy employees.

Reilly said, "My implementation manager told me with the HSI EHS Platform, the only thing that limits us is our imagination, and that's held true."

ED3 was impressed with the range and scalability of the HSI EHS Platform. It records safety incidents and observations while tracking inspections, maintenance requests, work orders, and job completions for equipment ranging from vehicles and lifts to substations and power poles. According to Reilly, "The scalability and robustness of the system convinced us the HSI Platform was the best option to meet our unique needs."

Two features were key in ED3's final decision: the ability to customize the system and accessibility for different users.

The ED3 team has complete control over the system to maximize efficiency. When they discover a new need, they can easily create a new checklist or workflow tool. If they hit a stumbling block, their HSI implementation manager is there to help solve problems and offer recommendations based on best practices.

The HSI EHS Platform is integral to maintaining a safe workforce. When a safety-related incident occurs, information is uploaded to the system, notifying the appropriate managers. Any necessary follow-up is automated, allowing ED3 to complete a root cause analysis to create better safety policies and arrange for safety training to prevent future injuries. Says Reilly, "We're to the point now where we have enough data in the HSI EHS Platform to do analysis on incidents and track trends to see what we're doing well and where we can improve."

These processes are all important for workplace safety, but the ability to automatically generate data for OSHA reports was another strong selling point for ED3. When it's time to submit regulatory reports, they're created from collected data in the agency's required format, reducing a several days process down to the click of a mouse.

The fleet shop uses the HSI EHS Platform to track vehicle and equipment maintenance. Employees perform daily inspections before equipment leaves the shop. If they notice something small, like a cracked taillight, the fleet manager receives a repair request with the vehicle's VIN, make, and model. The part is ordered, and the vehicle is repaired when the part arrives, minimizing downtime.

When a vehicle or piece of equipment needs a larger repair, the fleet manager gets an automated notification. The shop has 24 hours to diagnose or repair the problem. ED3 found reducing equipment downtime leads to a more effective and efficient workflow.

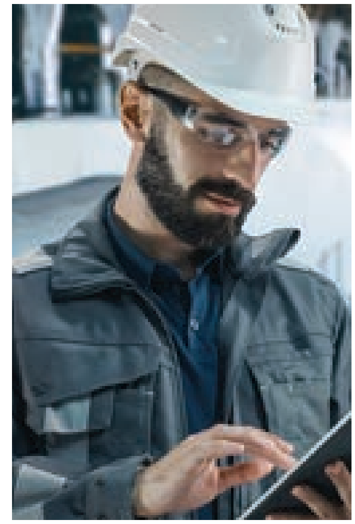
Checklists within the EHS Platform track the life history of the utility's 12 substations, showing completed inspections and tracking work orders. In addition, ED3 can track inspections for the more than 14,000 power poles within its service area, reducing pole failure and potential outages.

Efficiency and reliability are keys to customer satisfaction and the HSI EHS Platform helps ED3 improve both. Prior to implementation, if an inspector conducting a "meter read" found a problem, they would write a paper report and take pictures, spending the last two hours of their day entering this information into a spreadsheet. Not only did this waste valuable employee time, it was another opportunity for data entry errors.

Next, a coordinator would go through all reports, prioritize work orders, and submit them to the proper department. That department would start the planning process, which may include another site visit. Finally, after parts were ordered and received, the team would complete the work order.

Using the HSI EHS Platform, the inspector uploads the report from the field, including any photos, and the coordinator is notified immediately. "Because the information from inspections goes directly into the HSI EHS Platform, our inspectors spend less time on data entry and more time on field inspections or other important tasks," according to Reilly.

The technician can speak to the coordinator while still onsite and plan repairs or updates – reducing response times from two or more days to almost immediately.



After less than a year, ED3 has found efficiencies using the HSI EHS Platform. Hundreds of hours are saved per month, vehicles and equipment are back in the field quicker, and work order times have been cut in half. In addition, ED3 benefits from:

- Real-time tracking of safety incidents
- Less time on data entry, resulting in fewer errors
- Comprehensive data analysis to improve safety
- Faster, more efficient equipment maintenance
- Increased customer satisfaction with faster repair response times
- Streamlined OSHA reporting

ED3 uses the HSI EHS Platform to track safety incidents and observations to improve training and submit OSHA reports. Checklists in the plant and equipment modules improve workflows while tracking equipment maintenance needs, reducing repair downtime.

As ED3 continues to implement automations, it expects to become safer and more efficient, leading to an improved work environment where it can better serve the community.

STAYING AHEAD OF EMERGING RISKS

BY SUSAN PARTAIN, DIRECTOR, CONTENT STRATEGY, AMERICAN PUBLIC POWER ASSOCIATION

There are plenty of scenarios that could keep a utility employee up at night – what if one of the utility's networks is attacked by a cyber criminal? What if someone tries to vandalize a substation? What if the winter storms keep getting more severe?

The alternative to increasing anxiety about these issues is risk management. Beyond simply detailing plans for what to do following an event, risk management is a process that helps organizations to understand the suite of potential threats to all parts of their business and to spur a discussion about the threshold for tolerating consequences if action isn't taken to address these threats.

As utilities need to be prepared for a wider range of potential disasters, more utility employees are getting looped into the process to ensure a more comprehensive, proactive, and actionable approach.

Knowing the Threat Landscape

To maintain a continuous discussion about risk management, the American Public Power Association, through support from the Department of Energy, convened a Risk Management Working Group with public power professionals from across the country. The group began its work by developing a series of case studies that outline the major risks facing utilities and strategies to respond. The resulting documents, which are forthcoming as of this publication, cover the basic threat landscape for public power and walk through what potential strategies could help reduce those risks. The cases tackle three topics: a cybersecurity incident, flood risk, and physical threats to the grid.

Tom Spencer, the New York Power Authority's senior director of enterprise and operational risk management, who co-leads the working group's development of the case studies, said that the cases were selected to reflect the broad array of risk areas that are of greatest concern to the public power community.

The idea, said Spencer, is that "individuals could see how these case studies could tie into their day-to-day operations," so that if disaster happens, there is a ready answer to "What do you need to do?"

In addition to offering scenarios for utilities to work through, Spencer said the idea was to include information to give people a "big picture view" of the scope of the potential risks, rather than just a "slice." It also allows public power utility leaders to leverage the experience of other public power utilities.

The biggest challenge in developing a uniform risk management program for public power utilities, said Spencer, is that they have different levels of maturity in their risk management programs and use different technology to manage risk. As an example, at NYPA, his team has an internal enterprise governance, risk and compliance system that helps manage risk across the organization, whereas he recognizes other utilities might use spreadsheets for similar purposes.

"Given the differences in maturity levels, but similarity in many risks, we attempted to provide a wide spectrum of solutions," he said.

"A lot of organizations don't understand how important risk management is until a risk happens. And then, they ask, 'What should have we done?"

TONI HOANG, ENTERPRISE RISK MANAGER, SACRAMENTO MUNICIPAL UTILITY DISTRICT, CALIFORNIA

Rapid Change, Rapid Response

Because of the way risk evolves, the need for risk management has been exacerbated. Being able to respond quickly isn't the sole impetus for planning ahead. The complexity of some risks means that more stakeholders inside and out of the utility need to be engaged to make risk-informed decisions.

"We're great at responding to storms or events that happen," said Toni Hoang, enterprise risk manager at the Sacramento Municipal Utility District in California, but the increasing frequency of events requires a fresh look at how the organization and community can be affected. Hoang co-chairs the risk management working group along with Spencer.

Hoang said that SMUD had nine atmospheric systems come through its service territory in the last year, which resulted in "normal business" interruption to the community because of the storms.

"A lot of utilities are seeing more frequent and severe weather events, taking a more strategic risk-based approach to addressing these vulnerabilities are of substantial value to any organization," she said.

Hoang said that utilities have also been increasingly looking at how different communities might be more vulnerable to natural disasters, such as wildfires, and how that can impact day-to-day operations.

Utilities shouldn't only see risk in the form of damage to parts of the electric system or business networks. Other challenges, from volatile energy prices to supply chain constraints, can exacerbate risk and disaster events. Understanding the interdependencies of these risks can help organizations to better prevent or be more prepared for risk events, noted Hoang.

The variety of current dynamics and innovation bring a higher potential for risks that could occur, said Hoang. She defined risk management as a framework for identifying, assessing, tracking, monitoring, and communicating risks. An enterprise risk management program can help increase awareness of business risks across an entire organization, instill confidence in strategic objectives, improve compliance with regulatory and internal mandates, and enhance operational efficiency through more consistent applications of processes and controls. Risk management is also important in providing assurance to governing boards, credit rating agencies, insurers, and others that the organization has a process in place to manage and communicate risks appropriately.

Hoang noted the increasing resource constraints in the utility sector from multiple fronts, including people on the workforce, financing, and equipment. While utilities have always been under pressure to do more with less, she said that recent events and realities have ratcheted that pressure even higher, where utilities are being asked to make more changes and updates while having fewer resources at hand than in previous years. Enterprise risk management can help inform the decision-making process. Integrating it with the business planning and strategy process allows an organization to take a risk-based approach to focus on the highest areas of risk to the organization, allocating resources to the areas of the organization that are most in need considering the achievement of the organization's strategic goals and objectives.

"SMUD takes a risk-based approach in prioritizing capital spending," said Hoang.

"If you look at [the North American Electric Reliability Corporation], their models are changing to a more risk-based approach to compliance," said Hoang. "They are understanding that they themselves and utilities have very limited resources, and that when there are limited resources, we look to leveraging a framework that helps to manage risks holistically and allows us to prioritize and address the highest impact, highest probability risks to the organization first."

Another framework using a risk-based approach is from the National Institute of Standards and Technology, or NIST, which sets standards for cybersecurity.

Although the variety of entities have taken on a risk-based approach and mindset, Hoang noted that there is not a specific policy that pushed utilities to take this approach, but that it comes down to whether or not a utility or organization wants to be more proactive in understanding and recognizing risks.

As a parallel, she gave an example of how SMUD had developed a telework policy prior to the pandemic. While employees hadn't really put the policy to use in advance of the pandemic, having already had the policy, procedures, and technology in place made it fairly smooth for workers to transition into teleworking.

Evolving with Risk

"Risk evolves and our mitigation efforts have to evolve with that risk," noted Spencer.

Spencer said utilities should emphasize the process, rather than specifics, since risks change from region to region. He said that the five-step risk management lifecycle — identify, assess, respond, monitor, report — involves fairly uniform activities that could apply to different situations.

"Whether a wildfire or cyberattack, we all have some type of risks that we face," he said.

"Who needs to be involved has not changed, but who's wanting to be involved is changing." Hoang theorized that's because of the rapid rate of change affecting many areas at once and because technology connects more people and pieces of the utility than before.

That involvement needs to start with utility executive leadership.

"When your management and leadership teams emphasize risk management as part of the decision-making process, you will have more successful outcomes," said Spencer. He noted appreciation for NYPA's leadership's attention to risk. "We have a risk management slot at every board meeting, which sends a message that risk is important."

"Risk evolves and our mitigation efforts have to evolve with that risk"

TOM SPENCER, SENIOR DIRECTOR OF ENTERPRISE AND OPERATIONAL RISK MANAGEMENT, NEW YORK POWER AUTHORITY

"We all have very similar risks. How we react to it or mitigate it may be very different, but there's always lessons to be learned from other organizations."

TONI HOANG, SMUD

"A lot of organizations don't understand how important risk management is until a risk happens. And then, they ask, 'What should have we done?'" said Hoang. One common response is that risk should be integrated as a function throughout the entire organization. Her role is focused on working out how risk management can be integrated into everything from business planning processes to strategy development and compliance work.

A part of getting everyone involved in contributing to risk management is to run preparedness exercises.

"We run tabletop exercises all the time on a number of different scenarios, and different scenarios happening collectively. So, not just a wildfire, but a wildfire event with a cybersecurity event and physical security breach," said Hoang. "We do that with both internal and external players so that we all as a community have a good understanding of how we will respond and how we can prevent and plan for potential future event(s)."

Exercises not only help utilities to think through various risks and plan for a variety of contingencies, but also help people to become comfortable with risk management concepts.

Continuing the Conversation

The case studies are a first step in helping public power providers to better understand the risks associated with running a utility in this era. The next step for the working group will be to develop practical tools that will help public power providers identify, prioritize, and address the risks facing their utility.

For Spencer, the key is that there is now a year-round community of public power professionals focused on risk management.

"It's a credit to APPA for recognizing that there was a gap in risk management support. We talked about risk management at conferences, but the conversation didn't really continue in a formal manner," he said. "We took the initiative to start the Risk Management Working Group and are now formalizing a structure around it. I'm looking forward to continued involvement and keeping the momentum rolling."

He encouraged those who are not yet involved in the working group to either join in the conversations or ask working group participants for information and advice. He also said he hopes members will follow up after reading the case studies to note any areas for improvement and provide feedback on other information and tools they can use in their day-to-day work. One potential venue for sharing this information is on APPA's risk management online community group, which will roll out in 2024.

"We all have very similar risks. How we react to it or mitigate it may be very different, but there's always lessons to be learned from other organizations," said Hoang.

Ultimately, proactive risk management is about helping utilities to support their communities to be as resilient as possible.

After all, "without the community, the utility serves nobody," added Hoang.

WHERE MORE TRANSMISSION IS NEEDED

Transmission congestion costs topped an estimated **$20.8 billion** in 2022 – **$7 billion** higher **than 2021.**

Within the regional transmission organizations, these costs increased by more than **200% since 2016.**

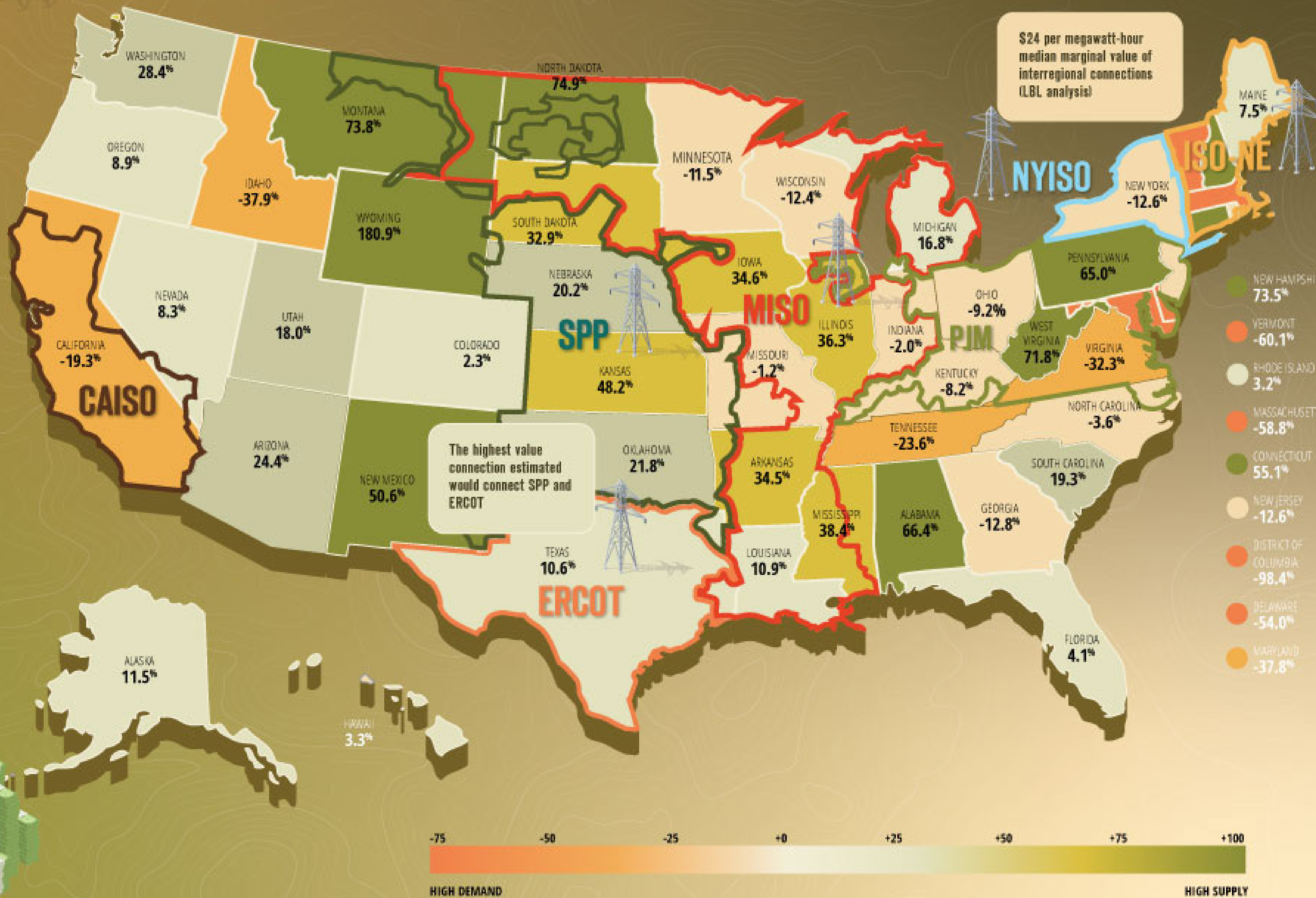
Alleviating these costs will require building and enhancing transmission capacity between areas with differences in power supply costs and need.

Extreme conditions and events skew the perceived value and need for transmission

TRANSMISSION CONGESTION COSTS, BY RTO

	2022 COSTS	INCREASE FROM 2016
ERCOT	$2,800	463%
ISO-NE	$51	31%
MISO	$3,700	164%
NYISO	$1,000	89%
PJM	$2,500	144%
SPP	$2,000	614%
TOTAL	$12,051	220%

DIFFERENCE IN MEGAWATT-HOUR SALES AND GENERATION BY STATE, 2022



Getting to K

A Q&A with Scott Corwin,

who started as American Public Power Association's president and CEO in August 2023.

What drew you to public power?

From my first work with public power 25 years ago, I was intrigued by the history, mission, and business model. With a background in government and policy, it is compelling to see the independent spirit of self-determination in these communities and the way they cut across political boundaries to serve this critical public need. I find endless opportunities to learn about electricity and the rich history of public power dating back to the late part of the 19th century. Even more important to me, the people I meet in public power are always welcoming and ready to lend a hand. Their passion and purpose make public power a place where we can really believe in and enjoy what we do every day.

What are you most looking forward to in your new role?

Getting to know APPA members and staff in a more comprehensive way is a thrilling prospect. I am fortunate to step into an association with great staff who understand our commitment to member service. I look forward to working closely with our board chair, Dave Osburn, and the other officers and board members who guide us with an inspiring depth of knowledge and experience. I had been working primarily in the western part of the country and created many lifelong friendships along the way. Having the opportunity to now reach people among the thousands of public power utilities across the country is exhilarating. Each day, I see new threads of the intricate web that makes up the public power story. I am looking forward to the constant influx of creative ways our members are meeting today's challenges and to helping build the tools for telling this story in our communities to a new generation entering the workforce.

What are your goals for APPA?

In the short term, my goal is to make sure we are doing all we can to execute on our strategy to help members meet the rapid changes in our industry. Critical to this is listening to, and acting on, the feedback from our board and members on what we should prioritize. Among the pieces underway are programs in cybersecurity, workforce, and governance; communications highlighting the value of public power; and ramping up grants from the Department of Energy and our Demonstration of Energy

now Our New CEO

and Efficiency Developments, or DEED, research and development program to enable implementation of technology.

Other goals revolve around continued advocacy so that the federal government imposes less regulatory burden and provides more partnership. This includes everything from finding solutions to supply chain difficulties to addressing the arduous permitting processes. Challenges like growth in demand from electrification and big data, the large amount of generation being retired, and regulatory constraints on new generation and transmission will require all our tools and talents. If the grid is to remain reliable and affordable, we must proactively shape the solutions and investments that will empower our members to meet these challenges.

Longer term, I see the association creating more opportunity for engagement with and between its members. Our utility and associate members, regardless of size, have a wealth of knowledge and best practices to share. Attendance at both live and online events should be easy, compelling, and affordable for our entire membership. A key component of "moving public power forward" as a foundational pillar for APPA is enabling all members to interact in a way that helps them proactively address industry change and effectively meet the future together.

What do you like to do when you're not working for public power?

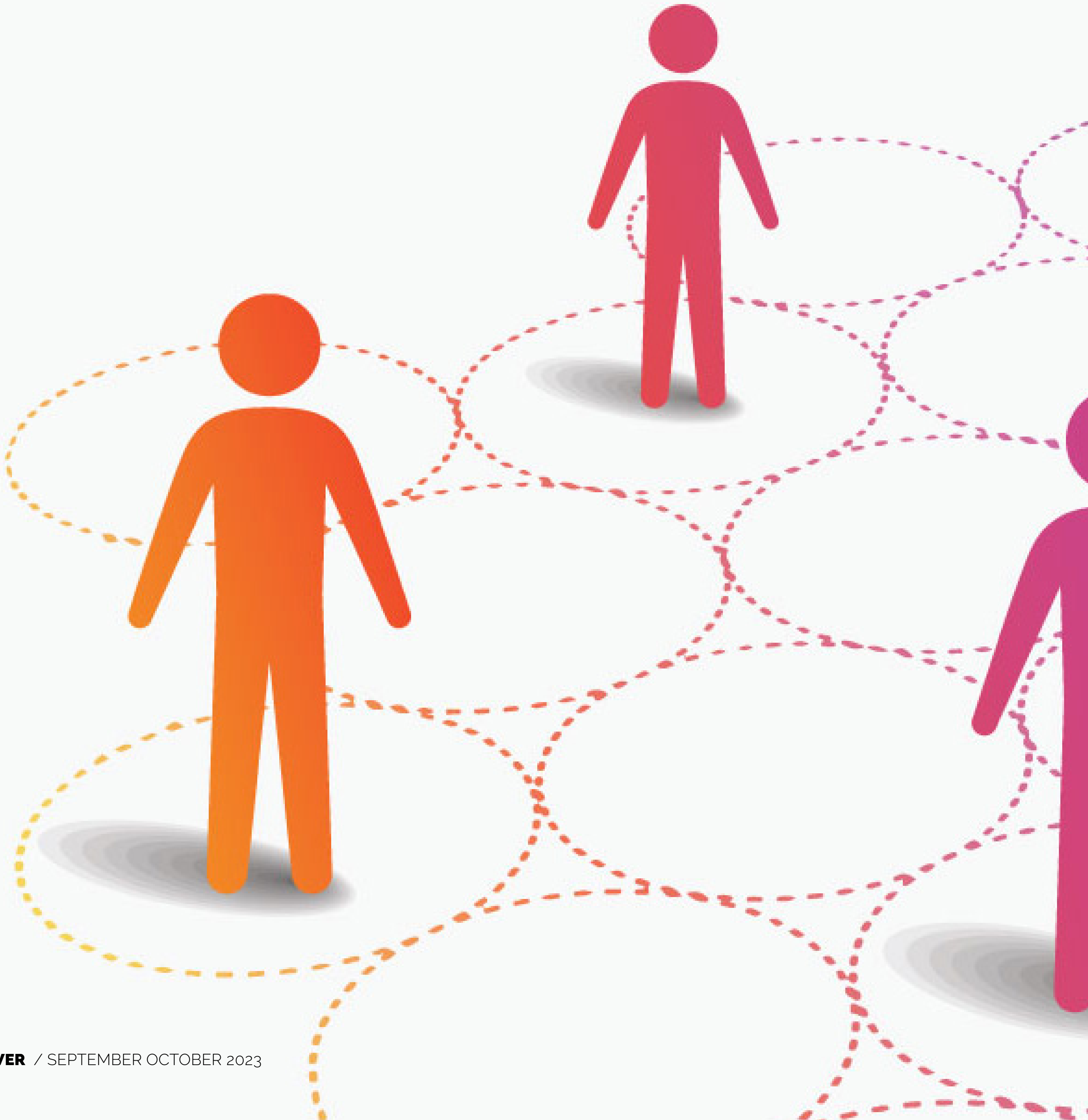
Being outdoors is a great way for me to recharge and get a fresh perspective. For much of the year, that means hiking, fishing, camping, biking, gardening, or just chasing after our dog. During the winter, our family heads to the hills almost every weekend to ski. Cruising down a mountain is a good way to focus and create a break from everyday concerns.

Is there anything else our members should know about you — or should ask about when they see you at our events?

It's been said that I have a dry sense of humor at times when speaking in public. So, I am always delighted when people ask me afterward whether a story was meant to be a joke or not. My goal at most meetings is to listen more than speak, so I really hope folks do not hesitate to reach out to me at any time. The more we know about what our members face on a daily basis, the better the job we can do.

The Future of

BY STEVE VANDERMEER, CONTRIBUTING WRITER



Joint Action

For nearly 100 years, joint action has played a significant role in the success of public power. Namely, joint action agencies helped public power utilities gain the buying power and economy of scale necessary to secure an affordable power supply. Today, the role of joint action is going through widespread reflection, as these agencies grapple with the roles they can — and should — be playing in a future where electric generation has shifted.

The History

Early in the last century, as generation technologies advanced, large generation projects — primarily coal and hydroelectric — became increasingly cost-effective. By the 1930s, it was becoming clear to many public power utilities that the best way to gain access to that low-cost, reliable power was through the formation of an aggregator of their combined demand. Thus, the first joint action agencies were born, starting with the Grand River Dam Authority in Oklahoma in 1935. Through the succeeding decades, JAAs expanded, with more than 80 across the U.S. in operation today.

The original charters of virtually all JAAs looked quite similar: Procure cost-competitive, reliable wholesale power on behalf of members through generation or purchase. For decades, this straightforward mission created tremendous value for public power, playing an integral part in maintaining retail rates lower than typically found among investor-owned and cooperative utilities.

Today, JAAs continue to embrace their original value proposition — aggregating member needs to leverage economies of scale — but are doing so in new ways to address a wide range of emerging issues. The new millennium has brought tremendous change to the electric industry, as changing fuel sources, new technologies, aging infrastructure, an uncertain regulatory environment, and shifting customer needs have all intersected to create new expectations of public power systems from their customers and their communities.

Evolving Needs

For many public power utilities, particularly smaller ones, the pressures on budgets and staffing can be enormous as they try to stay current on so many developments. Among the 2,000 public power utilities, about half have fewer than 2,000 customers, while many have only a few hundred. Staffing at these smallest systems might be a single person who maintains the lines, reads the meters, and drives the snowplow in the winter. For some utilities, purchasing new technologies, such as an advanced metering infrastructure solution, managing new construction, conducting safety training, completing a cost-of-service study, or even trimming branches away from lines, may be out of reach.

During his eight years with the Kansas Municipal Energy Agency, General Manager Paul Mahlberg has seen significant changes in his members' needs, and with them, several shifts in the role that KMEA plays in supporting those members. "We have watched many of our members coming to grips with a number of new challenges, from workforce development and retention to infrastructure maintenance and development, including severe challenges brought by supply chain issues," said Mahlberg. KMEA, a project-based JAA, serves more than 80 mostly small agricultural communities across Kansas.

Matt Schull, who was recently appointed president and CEO of Missouri River Energy Services in South Dakota, has been able to view joint action at work from a couple of perspectives, having previously served for seven years at ElectriCities of North Carolina. MRES has 61 members across four states in the Upper Midwest. "While joint action has become more complex, I believe the need for organizations such as MRES has only grown," said Schull.

Alice Wolfe, general manager of Blue Ridge Power Agency, has her own distinct view of joint action. Serving nine members in Virginia, including cooperatives and Virginia Tech, BRPA is a project-based JAA that manages no generation, relying wholly on negotiated wholesale power purchase agreements on behalf of its members. As such, Wolfe is one of only two employees with BRPA. With the small size of the agency, her focus necessarily remains on power supply and the impact of new regulations coming out of PJM and the North American Electric Reliability Corp. Yet she acknowledges the need to explore additional ways of adding member value.

"We've long conducted a two-day fall conference, and now we're adding a spring conference as well. Our conferences are small affairs, with only 10–15 utility attendees. That's a big commitment for speakers to travel into remote locations in Virginia, but I feel this is one of the benefits of being a small joint action agency, as the nine Blue Ridge members can chat with industry experts over lunch and dinner, and I expect that can be just as valuable as the presentations themselves," said Wolfe.

Assessing Needs

Given the wide range of services that a JAA *could* be providing, knowing exactly what it *should* be providing can be a daunting task. For Mahlberg at KMEA, the answer came through a combination of member discussions, strategic planning, and a willingness to capitalize on opportunities that presented themselves. Mahlberg said that KMEA engaged with Hometown Connections in 2018 on its strategic planning effort, including a facilitated retreat. KMEA also conducted a member survey to understand better what members needed most. Among the top-rated needs were lineworker services, system maintenance, and project management.

KMEA was well positioned to act when the opportunity presented itself. As Mahlberg describes, "Many of our members had a long-term relationship with a Kansas engineering and construction firm, Mid-States Energy Works Inc. As it became clear that our members were increasingly relying on outside expertise, the decision to explore acquiring Mid-States seemed like a natural next step." KMEA purchased it in 2020. Mahlberg said that the acquisition has proved very successful.

In 2023, KMEA again brought in a consultant to walk board and staff members through an update, validating whether the priorities that emerged in 2018 remained the most important to the organization. Member services continued to drive much of the conversation. As this focus grows at KMEA, who pays for what has become an important discussion point. "Our smallest members are the most at risk," said Mahlberg, "yet they also have the least ability to pay for those services. So, it's nice to see how supportive our large members have been, recognizing that KMEA can only be as strong as its weakest links."

This spring, Blue Ridge went through its own strategic planning discussions, which included surveys and group discussions. "It was the first strategic plan update in some time, and I was very pleased with how it went," said Wolfe.

The small number of members has made it relatively easy for Wolfe to remain engaged with those members. "We have had a lot of conversation about the big picture and what role Blue Ridge could play," she said.

MRES has gone through similar exercises to better understand member needs and challenges. "We just completed a strategic planning process that explored how our services can best match up with our members. We continue to face many power supply and transmission issues, but the real complexity has been in addressing our member services," noted Schull. "At this point, we view MRES more as consultants and facilitators to our members, helping them build the capacity in-house to succeed."

Yet MRES has also recognized

that there are times when more active intervention may be necessary. Like KMEA, MRES provides distribution maintenance for several of its members. Schull noted that through biannual member surveys and alternating-year in-person visits, MRES continues to seek ways to strengthen its partnerships with members.

Key Questions

Member services are a major theme emerging from these agencies as they plot their futures. And while smaller JAAs such as BRPA may not have the resources or staffing to quickly stand up a new service, access to those resources does not guarantee a clear path to expansion. Significant questions must first be answered.

To start are what services should be provided. Should they be those that the most members want or those that are most critical to the success of at-risk members? Next are funding issues. Should new services be funded solely by those members using them, or should there be some subsidization among all members? Then, there is the role of the JAA in providing that service. Should it seek to build capacity within its members or to create those functions within the JAA, or does it make more sense to contract out those functions? And finally, JAAs should consider how any end user-facing services get represented. Does the JAA step out from behind the curtain and build its brand with end users, or does it seek to position its members as the providers, with the JAA remaining in the background?

Answering these questions will help JAAs form a clearer picture of the role for joint action in the future. As the energy technology landscape grows and distributed energy resources continue to expand, JAAs and their public power utility members must work out how to respond as these changes bring tremendous opportunities as well as significant challenges to the way they operate.

“There is absolutely a role for joint action in the future. JAAs, such as KMEA, are going to be needed to help their members with their own success,” said Mahlberg.

As Wolfe at BRPA said, “We continue to explore new partnerships and strengthening our collaboration with members, including recently retired utility folks for help on projects.” And, concluded Schull, “The future is bright, but it continues to be important to track and respond to the evolution of the industry and public power.”

While the focus of joint action today has evolved beyond power supply, the need for greater partnerships and aggregating the issues of diverse members into effective solutions will likely remain for many years ahead.

Public Power Leaders: Kevin Wailes

A Q&A with Kevin Wailes, who has served as CEO of the Lincoln Electric System in Nebraska since July 2010. Prior to joining LES, he spent 23 years at the municipal electric utility serving Tallahassee, Florida — the last 15 years as general manager. Wailes also served as the superintendent of the Lamar Utilities Board in Colorado for six years in the early 1980s. He has served on the boards of the Colorado Association of Municipal Utilities, the Florida Electric Power Coordinating Group, the Florida Reliability Coordinating Council, the Southern/Florida Reliability Agreement Executive Council, the Florida Municipal Electric Association, and the American Public Power Association. He currently serves as a member and co-chair of the Electricity Subsector Coordinating Council and on the boards of directors of the Nebraska Power Association, the Lincoln Chamber of Commerce, and the United Way of Lincoln and Lancaster County. Wailes holds a degree in electrical engineering from Colorado State University.

HOW DID YOU COME TO WORK IN PUBLIC POWER?

I worked for an electrical contractor during my college years doing linework and industrial electrical construction. My senior electrical engineering project involved an investor-owned utility. What occurred to me out of that experience was that I didn't want to be in a big company where I was going to just be in one kind of engineering. When it came time to start looking for a job, I looked for a smaller utility that had all parts of the industry, and the position came up in Lamar (Colorado). The only other engineer was the manager, and the line superintendent was retiring, and so he wanted me to supervise the line crews, tree-trimming crews, and service crews — right out of college. The utility owned and operated generation, transmission, and distribution assets — even a gas transmission line and plant to fuel the power plant. So, one day I might be designing distribution lines, and the next day I might be troubleshooting in a power plant. The power plant manager went on extended leave, so I managed the power plant for a few months. Because it was a small utility, I got all that kind of experience. It was just one of those lucky opportunities.

WHAT KEY LESSONS HAVE YOU LEARNED FROM WORKING IN THIS SECTOR?

I became a passionate believer that public power is the best model. Being locally owned and locally governed provides such a wide array of community benefits. It's not just high reliability and low rates, but a culture of public service. A few years ago, our T-shirts for one of our events read, 'Helping people is what we do. Public Power is who we are' That kind of sums up public power.

It's the people in public power that make it work. The other tagline we commonly have is 'Local people serving local people.' In my mind, public power systems are planned and operated consistent with the values of the community they serve. Because of the size of most public power systems, we can provide a wide array of opportunities for our workforce — they can be involved in lots of different cross-functional teams and take on different kinds of assignments. They're not just isolated in one specific area and can learn more about what you do in the community that way.

I don't regret being in public power for a minute.

IS THERE AN ACCOMPLISHMENT YOU ARE MOST PROUD OF FROM YOUR TIME IN PUBLIC POWER?

Here, it's reducing our carbon dioxide emissions by about 50% from 2010 to 2020, while maintaining a diverse power supply portfolio. At the same time, we expanded our renewable energy production from an equivalent of 10% of retail sales to about 50% of retail sales and maintained some of the highest reliability and lowest rates in the country. When you have these accomplishments, it's not just you, it's all the people you're working with.

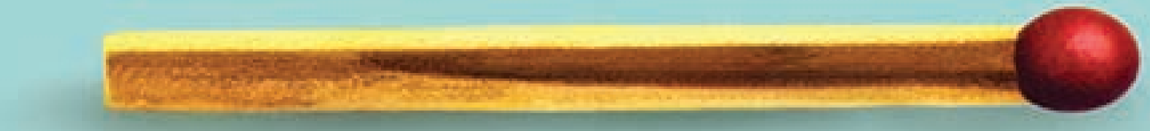
More broadly, how the Electricity Subsector Coordinating Council has developed over the last 12 years has been a great thing for our industry in terms of what we've been able to do with respect to physical security, cybersecurity, and mutual aid. Working through that group with our peer utilities, as well as with the federal government, has really enhanced mutual aid over the years and made the relationship between the industry so much stronger.

When we started, the industry did not have access to security clearances. That has changed dramatically, so we have access to information sharing, which is crucial. That emanated from our relationship with our federal government partners. That relationship is important, because when events happen, whether a cyber or physical security concern or a hurricane, we've got people we can call to get people together quickly. Those relationships give us the ability to be much more effective as an industry and recognize that electricity is important for the economy, public health and safety, and national defense.

WHAT CHALLENGES SHOULD PUBLIC POWER'S FUTURE LEADERS BE PREPARED TO FACE?

We have an awful lot of challenges that you just have to balance, and many of them are interrelated. Reliability, workforce, cybersecurity, supply chain — all of those things are interrelated. The climate extremes we're seeing are impacting reliability, as is the decarbonization effort and electrification. A lot of times people think electrification is just [electric vehicles], but it's much broader than that. If we're going to be moving away from natural gas for heating and cooling, then that means we're going to be using a lot more electricity, which means you've got to support much higher electric demands in winter.

IS THE TRANSFORMER SUPPLY CRISIS ONLY VISIBLE FROM WITHIN?



It has been two years since the American Public Power Association took up our members' concerns regarding the strained supply of distribution transformers, making it one of our top policy issues. We've held hundreds of meetings with federal officials, shared plenty of data and anecdotes showing the extent of the problem, and convened members to discuss solutions.

Utilities still have critically low stocks of transformers, and the lead times for orders are still often well over a year, if and when vendors respond to bids for orders. Yet, outside of the sector, skepticism about the problem remains. In some respects, utilities are the victims of their success on this front: Even though the supply of transformers continues to dwindle, the crisis is not seen as a problem because we continue to keep the lights on.

That doesn't mean there isn't hope.

ASKS TO CONGRESS

We pivoted from focusing on working with the Department of Energy to taking our appeal to Congress. This change in strategy has helped bring awareness of the issue to those outside of our industry. While we don't want to cause panic, there needs to be a broader understanding that something needs to be done, and recognition of the potential ripple effects across the country.

In August, the Government Accountability Office submitted a report to Congress, DOE Could Better Support Industry Efforts to Ensure Adequate Transformer Reserves. The report recommended that DOE develop plans to address industry supply chain challenges for transformers and other grid components, both in terms of what the agency can do to develop solutions to the crisis and how it can support utilities and industry sharing efforts.

We have also continually pushed back against proposed efficiency standards for transformers, which could make the problem worse in the short term.

Legislation has been introduced in the hopes of either adjusting or delaying the implementation of the transformer efficiency standard and to appropriate funding to increase production of distribution transformers. A problem for the latter, however, is in the uncertainty around the new efficiency standards and what kind of long-term market will exist for the components needed to create them. Manufacturers would have already needed to start changing their lines to meet the standards by the time they would go into effect, and the standards could push current domestic steel producers out of the market altogether.

As the appropriations process continues to unfold, utilities can continue to keep educating your members of congress about the real impacts of the problem — from reduced resilience after emergencies to stalled economic development.

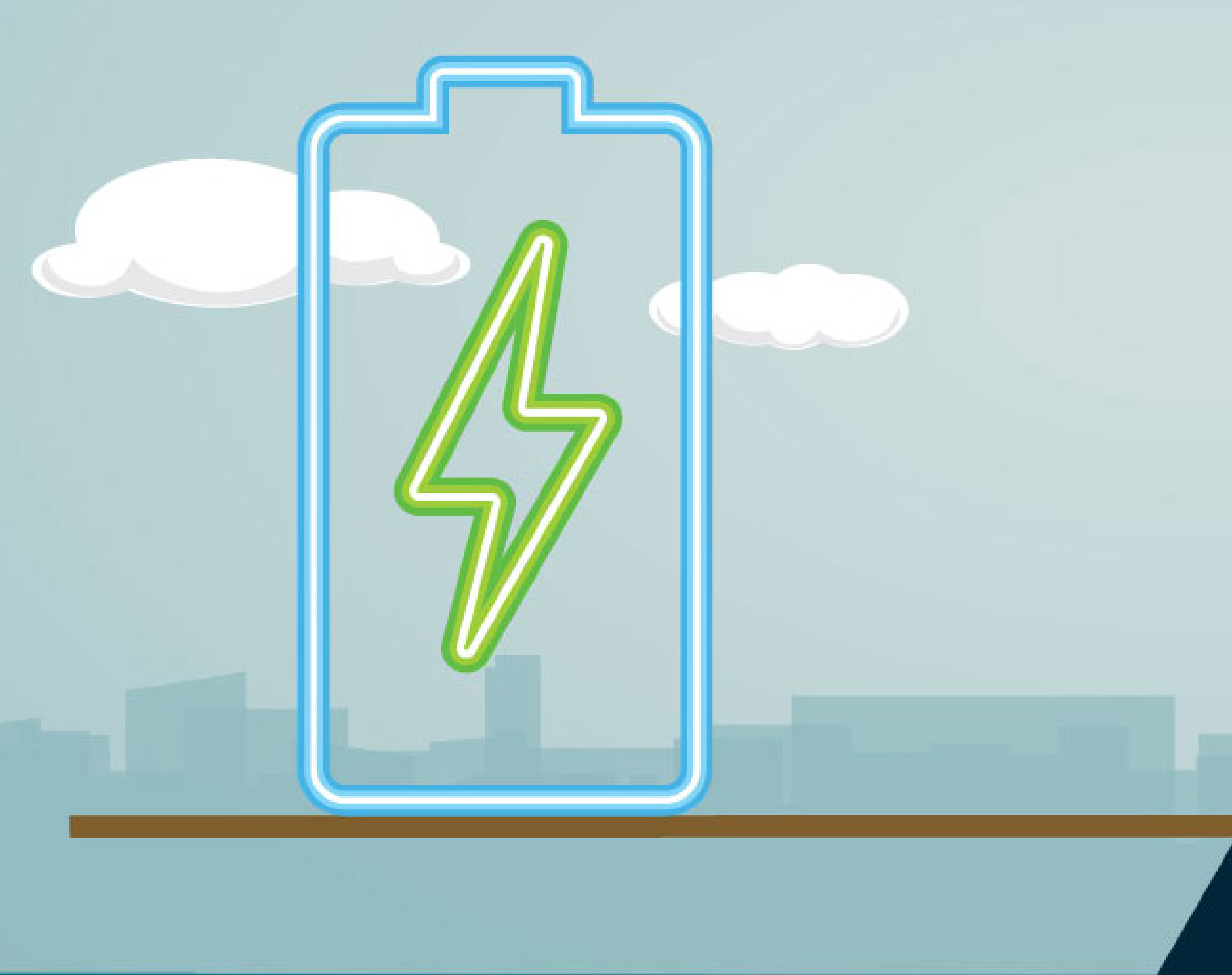
INDUSTRY SOLUTIONS

We are also continuing to convene key players across our sector, including DOE, to inform and refine potential long-term solutions.

Part of the reassurance to manufacturers is about our ability to send market signals that show the demand for transformers will continue to remain strong for many years to come. Initial findings from a DOE study on transformer demand support this message, dispelling the notion that demand for distribution transformers is cyclical and that other market forces, from population growth to electrification, translate to strong, consistent growth in the market for years to come.

Another key area of interest is around getting to some standardization of grid components. In August, the DOE Office of Electricity hosted a webinar for public power utilities to discuss standardization opportunities (the office also hosted webinars for investor-owned utilities and cooperatives). An overarching message was how trade groups must share in the work with DOE to identify opportunities to reduce the number of possible configurations for distribution transformers and related components — which DOE calculated to be about 80,000 different configurations in use, when all options and accessories were considered. These configurations are not so easily dismissible, as they account for differences in regional climate, load density, and voltage. The webinars were an early part of an ongoing effort to identify the opportunities for transformer standardization across the utility trades and with manufacturers. The effort will continue to convene meetings with these stakeholders into 2024.

We will continue to beat the drum at the federal level to ensure there is adequate support for both short and long-term solutions — and keep hoping that the interim solutions already deployed will be enough to keep the grid reliable.



Finding Balance – and Value – in Energy Storage

BY SUSAN PARTAIN, DIRECTOR, CONTENT STRATEGY, AMERICAN PUBLIC POWER ASSOCIATION

An ultimate promise of energy storage is that it helps to solve many of the reliability and quality concerns presented by an increasingly distributed, variable electric grid. While the technology and cost for energy storage systems that can truly meet this promise is not yet attainable, utilities are increasingly seeing the value of deploying existing solutions.

Benefits from energy storage include everything from better balancing the disconnect between areas of high demand, low generation and high generation, low demand; or offsetting transmission congestion costs; bringing down peak demand; and better understanding how to manage a future with a high concentration of distributed energy resources.

However, to ensure the greatest value in these assets, utilities need to carefully plan and consider how energy storage will work on their systems, which uses will deliver the highest value/return for the system, and what technology is right.

The Public Power Energy Storage Guidebook includes five case studies from public power utilities that have implemented energy storage projects. Here are some highlights from the examples and recommendations for how other utilities can refine the purpose, value, and benefits of energy storage for their projects.

Battery Learning Curve

Although a variety of storage technologies exist, the overwhelming majority of current applications center on lithium-ion battery energy storage systems, or BESS.

While BESS have become more common over the past decade, the array of regulatory considerations continue to evolve. Despite having state and local governments that are generally supportive of battery storage systems, utilities face a challenge of needing to educate those involved in the permitting process about the relative safety and environmental concerns of the systems, often while learning about these details themselves. Some public power utilities reported that this added education and coordination led to project delays.

Engaging with partners and subcontractors who have verified technical and safety expertise in installing BESS is critical, especially for utilities that do not have in-house experience or specialties in these areas.

The New York Power Authority is able to issue permits for its projects, which allowed for a relatively streamlined process for its North Country Energy Storage Demonstration Project, a 20-megawatt installation in the northern part of the state. However, New York State changed its building codes during the project implementation, which required staff to add in a review of the changes and any potential effects on the project.

The relative newness of BESS also makes for challenges in accurately planning for the long-term use of the systems. As noted in the case study from Lansing Board of Water and Light in Michigan, depending on how the system will be used, there may be limited history to allow for certainty

10 Steps to Consider

Public power utilities can take the following steps when implementing their own energy storage projects to avoid common challenges.

Assess current energy storage maturity level: The Public Power Energy Storage Maturity Model allows public power utilities to assess their preparedness for effectively planning, deploying, operating, and maintaining energy storage assets.

Conduct a feasibility study: Begin by assessing the specific needs, goals, and constraints of the utility, such as peak load management, renewable integration, grid stability, or cost reduction. A thorough feasibility study evaluates the technical, economic, and regulatory aspects of energy storage deployment in the given context.

Define project objectives: Clearly define the objectives and desired benefits of the energy storage project, such as peak shaving, grid resilience, emission reduction, or cost savings. Align these objectives with the utility's overall strategic goals and ensure they are in line with regulatory requirements and environmental targets.

Identify suitable technologies: Explore different energy storage technologies (e.g., lithium-ion batteries, flow batteries, or thermal storage) and select the most suitable technology based on the project requirements, including factors such as capacity, duration, scalability, efficiency, and lifespan. Consider partnering with experienced vendors or consultants to evaluate and select the right technology for the project.

Assess financing options: Evaluate various financing options, including grants, incentives, public-private partnerships, or third-party models. Seek opportunities to access funding or expertise in energy storage implementation in collaboration with federal agencies, industry associations, and research organizations.

Engage stakeholders and build partnerships: Involve key stakeholders — such as local communities, customers, regulatory agencies, and technology providers — in the planning and implementation process. Collaborate with industry partners, research institutions, and peer utilities to share knowledge, best practices, and lessons from similar projects.

Develop a comprehensive project plan: Create a detailed project plan that includes design, procurement, construction, integration with existing infrastructure, testing, and commissioning. Ensure compliance with relevant regulations, safety standards, and environmental requirements throughout the project lifecycle.

Monitor and evaluate performance: Implement a robust monitoring and evaluation system to assess the performance, effectiveness, and impact of the energy storage project. Continuously analyze data and gather insights to optimize the system's operation, improve grid management, and maximize the benefits derived from energy storage.

Promote public awareness and education: Engage in public outreach and education initiatives to raise awareness about the benefits of energy storage, promote energy efficiency, and encourage participation in demand response programs. Provide information and resources to customers and the community to enhance understanding and support for energy storage projects.

Continuously innovate and adapt: Stay informed about the latest advancements in energy storage technologies, regulatory developments, and industry trends. Foster a culture of innovation and flexibility to adapt to evolving energy landscapes and seize new opportunities that arise in the energy storage sector.

in predicting battery lifetime and performance, which can prevent these assets from being properly valued or included within planning studies or integrated resource plans.

Several of the case studies noted that timelines for projects implemented within the past few years had to be extended due to longer-than-anticipated lead times for key materials and equipment. Utilities stressed the need for flexibility in projects as long as supply chain constraints continue, as well as being aware of the potential for added costs from tariffs on imported materials. Such flexibility could be supported through developing a risk mitigation plan as part of the project design.

Bringing it Back to Rates

A clear objective across public power projects is to ensure that the implementation of energy storage can be done without needing to raise electric rates.

For Manitowoc Public Utilities in Wisconsin, which deployed two residential-scale systems, the rates question is not just about how the utility can reduce costs associated with peak demand, but what will drive customers to see battery storage solutions as an economical choice. MPU has a goal to have all its customer programs be self-funded, such as it does with a community solar program. The utility noted that more customers would need to switch to a time-of-use structure to be incentivized to invest in residential storage systems.

For Braintree Electric Light Department in Massachusetts, which implemented a 2 MW, 4 megawatt-hour system in 2018, the focus was on reducing transmission costs. The current system has so far been able to catch about 90% of transmission peaks, saving the municipal utility tens of thousands of dollars per month in transmission costs. While the savings benefits have been substantial, BELD noted plans to upgrade the system to one that can be discharged throughout the entirety of peak demand periods.

Also in Massachusetts, Wakefield Municipal Gas and Light saw how its 3 MW, 5 MWh BESS could reduce costs associated with peak demand. Since becoming operational, the system has been effective in reducing 95% of the utility's monthly peak demand charges. Despite these savings, WMGLD and other utilities reported a reliance on grants and other external funding sources to make the projects economical.

THE CHALLENGE WITH 100%

As lawmakers and communities push for increased renewable energy in the generating mix, it's important for them to understand the technical and economic challenges that come with transitioning to a system that relies on clean resources — and why it will take time.

THE PATH IS VERY DIFFERENT FROM REGION TO REGION

- Some regions already have a power supply that is majority from clean resources, whereas others would need to transition most or all of their supply

TECHNOLOGY NEEDS TO CATCH UP

- Current energy storage solutions can only provide a few hours of energy at a time
- Clean baseload resources, such as advanced nuclear are still in development

OVER-BUILDING IS NECESSARY

- Solar, wind, and other renewables accounted for 17.1% of capacity in 2021, but only 13.7% of generation
- In comparison, baseload resources (i.e., coal, natural gas, nuclear) account for just over 71% of capacity, but were responsible for nearly 80% of generation in 2021

AVERAGE CAPACITY FACTOR, BY SOURCE

SMALL GENERATORS ALSO POSE CHALLENGES

- Distributed generation – such as rooftop solar – can cause high voltage swings and other stresses on electric grid equipment

GENERATION ISN'T GUARANTEED

- Renewables are variable resources, which means how much electricity gets generated day-to-day isn't only a matter of whether the wind is blowing or sun is shining, but how much sun or wind there is

CONNECTION QUEUES ARE LONG

- More than 1,300 GW of capacity is in interconnection queues — as much as all capacity already in service
- 5 years: Median time expected for projects to wait to connect to the grid

SOURCES:

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2. www.publicpower.org/resource/americas-electricity-generating-capacity
3. https://emp.lbl.gov/queues