MARCH/APRIL 2022 • VOL. 80 / NO. 2

PUBLIC POWER MAGAZINE

AMERICAN PUBLIC POWER ASSOCIATION

DISTRIBUTION'S EVOLUTION

OKONITE

EXPANSIONS CONTINUE TO KEEP UP WITH DEMAND


Santa Maria, CA


Orangeburg, SC


Richmond, KY

Our previous 5 year plan to expand each of our three EPR manufacturing plants was completed last year resulting in over **50% increase in capacity of Okoguard EPR insulated cables.** Okonite continues to produce more EPR insulated cable than all of our competitors combined.

Most recently, we just commissioned our new Compound Plant expansion in Orangeburg SC. Okonite produces 100% of our own Okoguard EPR compound at this facility. The expansion involved a brand new and completely redundant compound production line using state of the art equipment along with an addition of 85,000 SF, resulting in a **100% increase in Okoguard EPR compound production capacity.**

Okonite's continuous expansion and modernization programs are an everyday part of our long term vision. Come see our facilities first hand and share our contagious excitement about the future of Okoguard EPR insulated cable. Okonite has been setting the standard since 1878. We are 100% Made in America and an employee-owned company!

THE OKONITE COMPANY

Okonite Cables...A higher Standard!

MADE IN THE USA
QUALITY CABLES SINCE 1878

102 Hilltop Road, Ramsey, NJ 07446 201.825.0300 www.okonite.com

APPA ACADEMY | AMERICAN PUBLIC POWER ASSOCIATION

Join Friends and Colleagues

Meet with public power friends and colleagues from around the country. The APPA Academy offers professional development opportunities for all your networking and learning needs. Learn more and register for all events at www.PublicPower.org/APPAAcademy

Supply Chain & Management Summit

May 5 – 6 | Arlington, Virginia OR Participate virtually

Get updates on current supply chain disruptions, learn how other utilities are managing risks, and share strategies for dealing with these challenges.

National Conference

June 10 – 15 | Nashville, Tennessee

Engage with visionaries, exchange strategies and solutions with public power leaders and policymakers, and discover tools for your future success as changing policy, technology, and lifestyles are reshaping the energy industry.

Business & Financial Conference

September 18 – 21 | Savannah, Georgia

Empower growth through new ideas and approaches to pricing, accounting, risk management, information technology, and human resources.

Fall Education Institute

October 3 – 7 | San Antonio, Texas

Advance your abilities through in-depth courses on accounting, work order and asset management, cost of service and rate design, overhead distribution systems, and the new National Electric Safety Code.

Legal & Regulatory Conference

November 7 – 10 | Colorado Springs, Colorado

Join energy attorneys and regulatory personnel for professional development, networking, and updates on federal legislative and regulatory changes impacting public power.

Customer Connections Conference

November 13 – 16 | Minneapolis, Minnesota

Network and strategize with public power experts in public communications, customer service, energy innovation, and key accounts.

In-House Training

Let us customize courses based on your needs. Instructors will come to your facility to conduct in-person training, or we can bring you the training you need in a virtual format. For details, contact EducationInfo@PublicPower.org or call 202-467-2921.

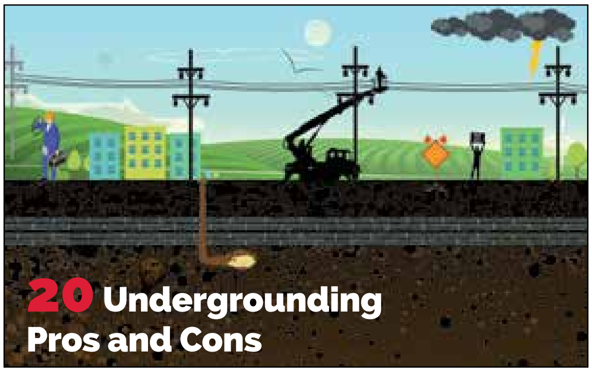
Learn more at www.PublicPower.org/APPAAcademy

AMERICAN PUBLIC POWER ASSOCIATION
Powering Strong Communities

PUBLIC POWER MAGAZINE

MARCH - APRIL 2022

DISTRIBUTION'S EVOLUTION



EDITORIAL TEAM

David Blaylock
Director, Digital Content and Data Analysis

Paul Ciampoli
News Director

Tanya DeRivi
Senior Director, Member Engagement

Julio Guerrero
Graphic & Digital Designer

Susan Partain
Senior Manager Content Strategy

Sharon Winfield
Creative Director

INQUIRIES

Editorial
News@PublicPower.org
202-467-2900

Subscriptions
Subscriptions@PublicPower.org
202-467-2900

Advertising
Tima Good, Tima.Good@theygsgroup.com

Advertising is managed by The YGS Group.

Public Power Magazine (ISSN 0033-3654) is published six times a year by the American Public Power Association, 2451 Crystal Drive, Suite 1000, Arlington, VA 22202-4804.

Opinions expressed in articles are not policies of the Association. Periodical postage paid in Arlington, Va., and additional mailing offices.

For permission to reprint articles, contact News@PublicPower.org.

AMERICAN PUBLIC POWER ASSOCIATION
Powering Strong Communities

ABOUT THE AMERICAN PUBLIC POWER ASSOCIATION

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.

Postmaster, send all address changes to:
American Public Power Association
2451 Crystal Drive, Suite 1000
Arlington, VA 22202

Distribution Is Less and Less About Distribution

By Joy Ditto, president and CEO, American Public Power Association

As the way utilities manage the distribution system evolves, the term itself is becoming more of a misnomer. Let me explain. Discussions about "distribution" nowadays seem to focus more on acquisition. From how energy is generated and delivered, to preparing a specialist workforce and being able to procure a wider variety of equipment and technology, a lot of effort is put into what the system needs to gain rather than disperse.

Of course, there is still a lot of (increasingly complex) attention given to how to allocate system resources to customers and in keeping a utility's part of the electric grid balanced and reliable. Utilities are dealing with the added and continued challenges of a strained supply chain, cybersecurity threats, and shifting rules and regulations. With these challenges come opportunities to change.

I've heard from members over the years who appreciate when the American Public Power Association focuses on "the basics" of utility operations. Our technical and operations team does a good job of providing programs and informational resources that help public power utilities execute these basics well, such as through producing the Distribution System Reliability and Operations Survey Report every few years. This report is just one of several that can help utilities to benchmark their operational structure. Yet, looking back across the years of this report and how our programming has changed, it is clear that these "basics" are evolving.

In some ways, this issue of *Public Power* magazine is about getting back to relaying those basics — in highlighting the latest survey report findings (see page 40), reviewing how to reduce system losses (see page 36), and in keeping the distribution system reliable (see page 22). In other ways, it reflects the number of ways that these basics are changing, from how lineworker apprentices get trained (see page 33) to how utilities are exploring non-wire alternatives (page 12) and deploying automation and artificial intelligence (see page 28).

As energy technologies evolve, utilities will increasingly find that customers and competitors might be one and the same. This is all a matter of perspective, of course. As public power, our aim is to serve the best interests of our communities, and as the cost of distributed energy resources comes down (and access to these technologies increases), it may be that customers will benefit from generating and using their own energy. This doesn't need to undermine or work against a utility, but rather requires an adjusted mindset about what it means to be a distributor. It's about exploring how to apply our expertise to be seen as energy advisers and making sure we're part of the energy conversations happening in our communities.

As APPA staff knows by now, I'm all for doing away with practices that no longer make sense — especially if it means increased attention to the practices that matter most. Operating a top-notch distribution system means looking at a broad variety of factors — exploring new technologies, making sure we are attuned to our customers, and continually evaluating what's working and what isn't. And APPA is here to support our members in each of those aspects.

What makes a system reliable and affordable now isn't necessarily what will make it so in the future. Applying lessons learned today and laying the foundation for success — whether in daring to explore these technologies or digging into analytics to better understand emerging patterns — will make the reliable, affordable system of tomorrow. I look forward to seeing how public power will continue to evolve the concept of distribution and being part of the discussions on how we will get there together.

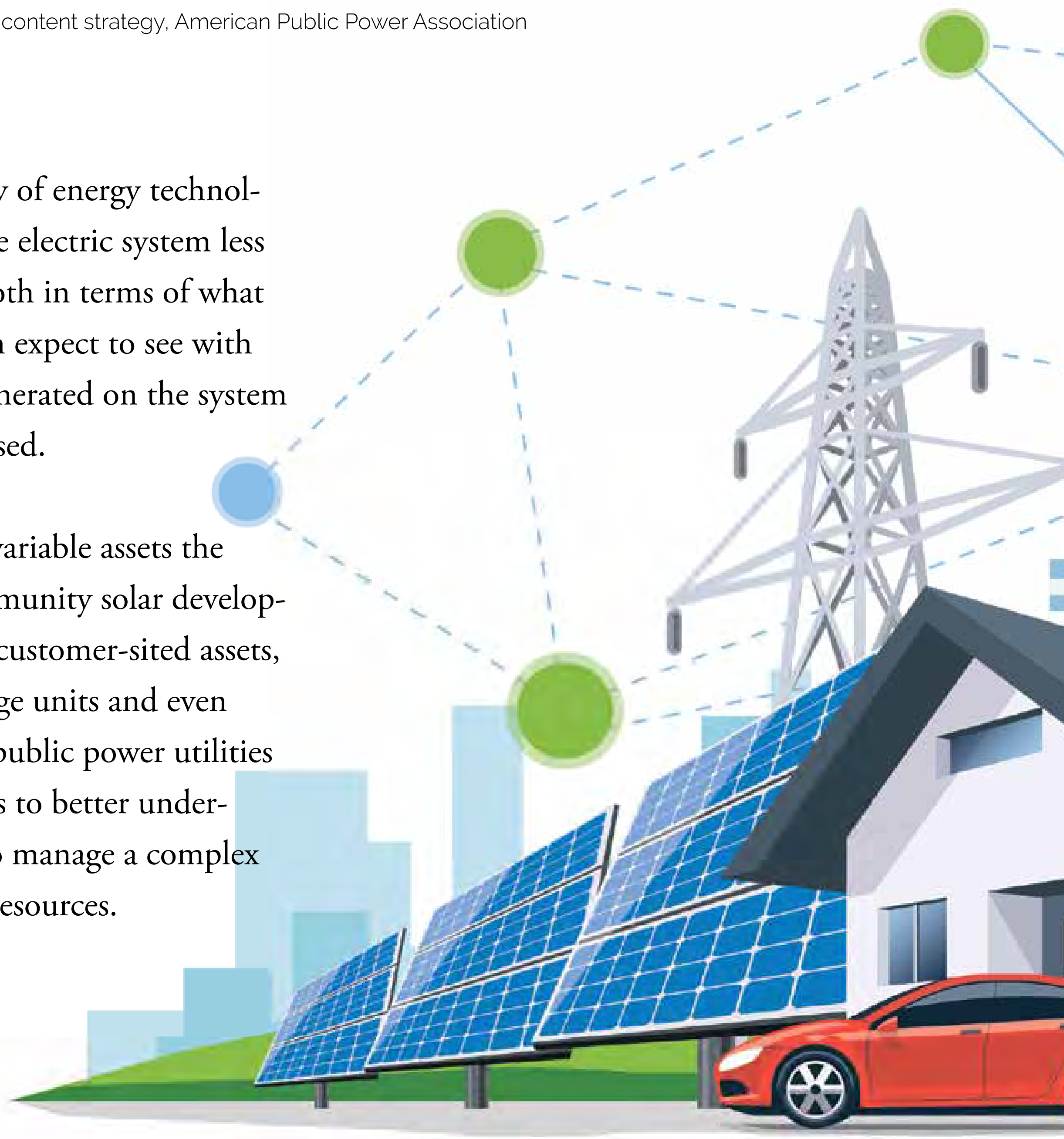

PLAN
ANALYSIS
PRODUCT
PROFIT
PROCUREMENT
DISTRIBUTION
MANAGEMENT
CONTROL

Making New Connections: **Incorporating and Preparing for Distributed Energy Resources**

By Susan Partain, senior manager, content strategy, American Public Power Association

An increasing array of energy technology is making the electric system less predictable — both in terms of what utility operations staff can expect to see with regard to energy being generated on the system and in how it is getting used.

Whether in managing variable assets the utility owns, such as community solar developments, or understanding customer-sited assets, from solar panels to storage units and even electric vehicle batteries, public power utilities are taking important steps to better understanding and preparing to manage a complex set of distributed energy resources.



Passing Along Expertise

American Municipal Power, Inc., a joint action organization serving 134 utilities across nine states, looks at how distributed generation and other resources can help its members both in terms of direct operating benefits and in building customer relationships.

Willey Sandell, vice president of generation operations and development, noted how for AMP and its members within the PJM market territory, installing behind-the-meter generation and resources can provide significant savings and help to counter rising capacity and transmission costs. AMP has about 60 megawatts of solar capacity, over 200 MW of natural gas combustion turbines, and another 80 MW of small reciprocating diesel generators that help with peak shaving. Sandell said these assets also can be isolated to support overall reliability for the system or for specific areas that otherwise would experience an outage.

Sandell noted how despite many DERs being newer technologies, utilities and organizations like AMP have been exploring and working to understand these technologies from their onset, making them experts on the technologies. And that experience can be transferable to utility customers with questions about DERs.

"AMP has developed sample interconnection agreements, applications, and materials for its members to develop behind-the-meter rooftop solar policies"

"We want to make sure our members are prepared and are at the table to ensure the DERs deployed benefit the customer and community," said Erin Miller, AMP's assistant vice president of energy policy and sustainability.

As costs for DERs and behind-the-meter assets have come down, Miller noted that interest in the technologies has gone up. AMP has developed sample interconnection agreements, applications, and materials for its members to develop behind-the-meter rooftop solar policies to help members bring these assets into the utility's fold. It has also created guides for members to share with customers on asking the important questions about the real costs and considerations that need to go into deployment, such as how installing rooftop solar might affect a home's roof warranty. This type of support helps member utilities to serve as a resource to their customers.

Beyond helping with customer relationships, providing this kind of guidance to utilities helps to make sure they're at the table "so that they know what's happening on their distribution system for the safety of their lineworkers and the reliability of the system," added Miller.


40
Feb.
May.

Building for the Future

Laura Duncan, manager of origination and renewable support at the Tennessee Valley Authority, sees the work that utilities and TVA are doing now around tracking and encouraging distributed energy resources as helping set the foundation for the grid of tomorrow. She sees the role for TVA and utilities changing to become more of partners, or trusted energy advisers, to a growing array of customers and stakeholders.

Duncan said that "proactive engagement is the key" to managing and monitoring adoption of DERs. This includes having conversations and forming partnerships with utilities, business customers, solar installers, and others who have an interest in DERs. Duncan has been supporting TVA's Green Connect program, which helps local utilities and businesses to invest in DERs, mostly small-scale solar. Since launching in 2021, the program has helped customers install nearly 200 systems with a collective capacity of about 1.5 MWs.

For Duncan and TVA, advising on and managing DERs comes back to the fundamentals of the public power model, which is "driven by the public benefit, doing what's best for our communities in the areas we serve," said Duncan. That includes being able to attract and support businesses in meeting their sustainability goals, with an eye on how to keep energy costs low for the region, and adequately supporting customer choice.

""We really need to be working together to identify which technologies are most critical and how we're going to manage those technologies," said Duncan. "

That means being part of conversations that influence where DERs get installed, so that they can support the grid and offer value to the grid and the customer. The other side is for utilities to make sure that interconnection technology and procedures are in place.

"We really need to be working together to identify which technologies are most critical and how we're going to manage those technologies," said Duncan.

TVA has its regional grid transformation initiative, which is working with the 153 local power companies across the region to identify when new system capabilities and technologies can be introduced, and then how each area can do so in a strategic, cost-effective way. The initiative, like TVA's green programs, rely on ongoing communication and bringing a variety of players to the table to ensure everyone's perspective is heard.

"It's not like everyone's coming together in agreement saying these are all the great benefits from day one," noted Duncan. "It's really that working through it together, building trust."

Preparing for Electrification

Lincoln Electric System in Nebraska wanted to stay ahead of the curve and understand how electric vehicle drivers in its territory charged, and to what extent utility actions and communication could affect charging during expected periods of peak demand.

Getting to this data started with examining EV charging habits beginning in 2019. That involved putting a module into the car's diagnostic port that could track when and where the car charged. To recruit for the study, explained Scott Benson, manager of resource and transmission planning, LES hosted a breakfast for owners of both battery electric vehicles and plug-in hybrid vehicles in the area to talk about the study and ask attendees to spread the word to other EV drivers they knew. LES also trained its board and staff to recognize different EV models that might be in the area and gave them copies of an informational card about the study to give to drivers or put in car windows. The effort led to getting about 90 participants in the study, which Benson estimated represented about one-third of the EV drivers in the area at the time.

From there, LES asked study participants about participating in a demand response pilot in 2021. The pilot consisted of LES sending participants an email and text about 24 hours before an expected peak load period, asking them to refrain from charging during the predicted peak window. Drivers could receive a $10 credit on their bill if they did not charge during all of the peak windows in a month. All of the study participants who were still active and within the service territory — about 70% of the original study participants — participated in the pilot.

The pilot mostly looked at summer weekday evenings, June through September, when the public power utility typically sees its highest peaks, but also during its winter peaks in mornings and evenings in January and February. Benson said there were about five events in a given month, and that most of the participants refrained from charging during about four out of the five events. The average compliance across all 30 individual peak events was 88%.

Benson stressed that changing up EV charging is different than asking people to reduce usage of air conditioning systems, as the load is neither constant nor directly driven by the weather.

"On a 100-degree day, the one thing you know, everybody's air conditioner is going to be on probably for the whole two-hour window, unless you do something about it. This is not the same," said Benson. Most drivers in the area, he mentioned, will charge every two or three days and can easily move up or bump back charging if there is an identified need.

In the LES service territory, Benson said, area drivers do more than 90% of charging at home, and usually this charging occurs in the evening when EV owners return from work. As such, there wasn't a noticeable difference in charging behavior for the winter morning peaks, but the number of vehicles charging during both the summer and winter evening peaks did decrease.

Benson said the pilot wasn't about getting a payoff in terms of peak reduction at this scale, but it can translate to savings if the findings are representative of charging behavior and norms for when adoption is much higher. "When we call an event, if only 10–15% are going to be charging anyways, but if you have tens of thousands, that makes a difference," he said. The findings could also help the utility to avoid overload at the feeder or distribution level, if there was a recognized cluster of EV owners in a specific neighborhood or area. LES found that the average instantaneous charging demand for at-home charging for all-electric models seen in its territory is about 8 kilowatts, and about 4 kWs for plug-in hybrids.

However, Benson did note that the study participants, who consist of early adopters, likely are already more tuned into the utility's resource needs and the importance of conserving energy.

"If you project going forward and want to do this with a lot of your customers when EVs aren't special … you're going to need some kind of incentive," said Benson.

He noted that having the module plug into the car is not ideal at greater scale and would prefer a system where the utility could interact with a home charger over Wi-Fi. Such a system would be more akin to demand response programs that interact with water heaters, for example, as people who have signed up for the program could authorize LES to instruct any connected chargers not to charge during peaks, instead of having to solely rely on people to remember not to plug in during those peaks.

EXPLORING NON-WIRE ALTERNATIVES IN WIRED INDUSTRY

BY TANYA DERIVI, SENIOR DIRECTOR, MEMBER ENGAGEMENT, AMERICAN PUBLIC POWER ASSOCIATION

Many utility goods are in short supply, including transformers, which have order time frames of a year or more. Even before the pandemic, utilities were evaluating how best – or how else – to deliver electricity to customers in our increasingly constrained world. Today's challenges involve a combination of equipment shortages, grid congestion, rate and regulatory pressures, land constraints, aesthetic considerations, and permitting delays so often involved with major infrastructure projects.

Whether it is for reducing line losses and improving efficiencies, shoring up grid resiliency, or reinforcing the role customers can play in shifting energy loads, utilities are working to assess "non-wire alternatives."

EXPLORING NON-WIRE ALTERNATIVES IN A WIRED INDUSTRY

DEFINING ALTERNATIVES

"Non-wire alternatives" are technologies or operating practices intended to reduce grid congestion and manage peak demand to offset a utility's need to make additional investments in conventional assets like wires, poles, and substations. The technologies can include distributed energy resources, such as microgrids or batteries, and practices and programs focused on load management, demand response or energy efficiency.

Such alternatives might have previously been deemed too costly to pursue or might have raised unacceptable reliability concerns for public power utilities. Yet the supply chain is expected to continue to be strained as utilities expect to have increased needs for electric grid equipment in the coming years. A recent survey from the American Public Power Association showed that utility leaders were concerned about the availability of transformers, meters, bare wire, and underground residential distribution wire.

As a result, non-wire alternatives may become more feasible and achieve greater cost competitiveness. A recent Wood Mackenzie report finds that front-of-the-meter battery storage has been the non-wire alternative technology of choice to date. Compared with other resources, battery storage accounts for most project capacity currently being implemented, with federal regulations likely strengthening this trend going forward. How technology has evolved in power system planning tells an interesting story.

EXPLORING "BIG BUILD" ALTERNATIVES

Public power has a history of evolving system planning based on local input. Transmission towers, with their long swaths of wires crisscrossing the landscape, might be the most recognizable power system asset. They are also some of the most difficult and controversial projects to permit and build.

Non-wire alternatives that could replace multi-mile infrastructure builds have offered solutions, especially as the cost of solar plummeted over the last decade and other resources, like battery storage, become more viable. In recent years, demand response programs have taken center stage in areas facing extreme temperatures that threaten to overwhelm the grid (or that have overwhelmed it already).

It marks a transformative step in advancing targeted, less obtrusive power system solutions over large, centralized structures that could fall victim to budgetary constraints. Especially as utilities plan to meet load growth driven by substantial electrification efforts, they are looking for how to best control that additional load and the associated costs while limiting the amount of physical infrastructure needing to be built. Such targeted solutions also become relevant for public power utilities constrained by transmission congestion issues.

With big demands outlined in planning processes come big opportunities. Grid congestion problems could increasingly be addressed more economically with localized solutions: microgrids, energy storage, energy efficiency, demand response, virtual power plants, advanced software, congestion relief by updating existing business practices, aggregation techniques, or any combination of such alternatives. They may also offer more flexibility and future scalability – plus be more operationally efficient – to maintain grid reliability.

The trend has also taken shape at the state and federal levels. California, Hawaii, and New York have taken much more active roles in grid investment planning. So has the Federal Energy Regulatory Commission through Order 841, which directed each independent system operator and regional transmission organization to create market participation rules for storage resources given their unique attributes.

EVOLVING WITH TECHNOLOGY

The Alabama Municipal Electric Authority was established in 1981 as a joint action wholesale power provider for 11 public power utilities in Alabama. Collectively they serve approximately 350,000 people across small towns and mid-sized cities. AMEA provides low-cost electricity through wholesale power contracts, owned generation, and by helping to lower demand through various initiatives.


spright
Scalable, BVLOS drone inspection solutions to meet your budget.
Want to learn more about our end-to-end partner solutions?
Visit www.sprightutility.com

EXPLORING NON-WIRE ALTERNATIVES IN A WIRED INDUSTRY

Arthur Bishop, AMEA's manager of transmission and distribution technology support, shared how AMEA's load management program has evolved over 20 years. It began by installing load control receivers on member customers' air conditioners and water heaters in the 1990s. "These were activated via radio signals during peak periods, with some members also stopping pumps and starting generators at water or wastewater plants," he said.

Technological advancements and the structure of power contracts evolved this approach. AMEA's members next used their joint action agency to install SCADA systems. Each then leveraged a smart grid initiative to help upgrade their distribution systems.

"Upgrading member substations with the latest smart regulator panels and using conservation voltage reduction helped to lower peaks with precision – and with verifiable data," Bishop explained. AMEA now has 30 megawatts of conservation voltage reduction available, with an additional 20 MW possible within the next two years, once all members have advanced metering infrastructure systems in place. The combined 50 MW would represent about 6% of AMEA's total peak load. "Further testing shows the percentage capable down to a feeder level with AMI also providing higher reliability and flexibility using bellwether meters that provide near real-time data back to SCADA for monitoring while activated," Bishop said.

AMEA also has a program for renewable behind-the-meter generation for member customers and has installed community solar parks in each member city to study solar usage during peak periods. That led to a 100 MW utility-scale solar project being built in south Montgomery County, Alabama, that is expected to be in-service in January 2023.

Bishop said future contract changes will allow for even more flexibility in distributed generation. "AMEA is exploring adding storage at both the community solar and utility-scale projects, as well as upgrading member-owned generation to more efficient units and additional units at other member facilities."

LEVERAGING BLOCKCHAIN TECHNOLOGY

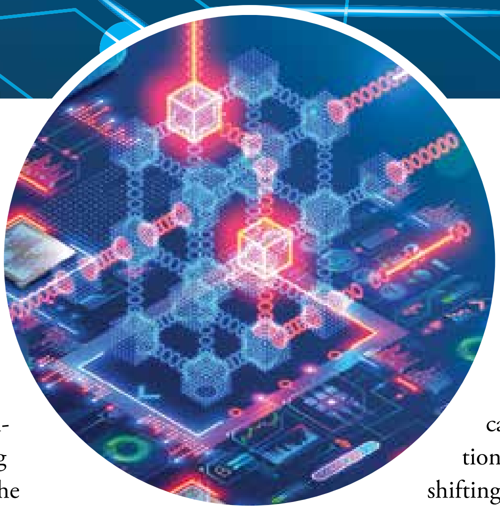
The Burlington Electric Department is Vermont's largest municipal power utility. It serves over 21,000 customers across approximately 15 square miles with a generating mix of owned and purchased power that has been 100% renewably sourced since 2014. Almost all of BED's energy comes from roughly equal shares of biomass, hydropower, and wind.

Casey Lamont, a resource planning analyst, constantly looks for ways to reduce costs and provide additional customer benefits. One such effort was using funding from APPA's research and development program to pilot a demand response program in 2019 using blockchain technology. Together with Omega Grid, LLC, the utility set out to demonstrate that wholesale electric market costs could be reduced using dynamic blockchain market incentives. The goal was twofold: 1) to reduce capacity and energy costs for the utility by better managing new distributed energy resources on the grid and 2) to incentivize more customers and devices to participate by exploring immediate low-cost and faster settlements using tokens on a blockchain. The value of those tokens was "trued up" once Burlington knew if an action had helped reduce the utility's load during the peak hour.

Most demand response programs focus on enrolling larger customers to maximize demand reduction and cover the overhead of engagement. Increased solar penetration, however, has begun to shift peak demand hours into the early evening, generally away from times when larger traditional demand-response participants experienced their demand peaks.

Burlington and Omega Grid theorized that lower cost and faster settlement of transactions enabled by a blockchain-based system could lower the cost to implement a demand response system and enable a greater diversity of customers and devices to participate. Blockchain transactions, and digital technology generally, could thus result in lower costs, enabling broader participation. They also believed that participants would want more control over how they managed their response to the predicted events by offering a bid reflecting their cost to reduce load. Instead, during implementation, they realized that customers wanted a simpler incentive and were not interested in determining their response thresholds based on bid prices.

The pilot demonstrated that it was possible to run a blockchain-based demand response program that could serve a diversity of participants with low-cost transactions. The pilot also identified some needed refinements to move to a larger scale.



"It was a broad-based program where anyone could join and we were sending messages to customers, but we did not have a direct way of determining their response, beyond meter data," Lamont said. The pilot also demonstrated to Burlington Electric "the value of targeted programs and automated response."

The effort also explored how a demand response program could be designed to better predict the value of peak events and, for customers, how the onboarding, communication and engagement with customers could be leveraged. Burlington learned that the system could be further enhanced by streamlining methods to onboard customers, automating communication with building management systems, and adding tools for device owners to test that their system is performing.

According to the final report, "Any public power system that is subject to transmission or capacity charges and the ability to monetize reductions in those charges, or able to benefit from load shifting could find a similar program to be beneficial. The benefit to a public power system would be proportional to the costs that they would be able to reduce under such a program." Burlington Electric realized a total savings of $14,579, with 70% of that amount returned as customer incentives. The report added that as the importance of bulk or wholesale sources of electricity is minimized in favor of more load flexibility, local generation, and storage, decentralized technology such as blockchain could be helpful in managing many more potential new grid assets as well.

AN UNUSUAL NOR'EASTER TESTS THE NEW NEPPA MUTUAL AID SOLUTION

OVERVIEW

THE NEED

A tool to respond quickly to weather events, communicate between different organizations, share resources quickly.

THE SOLUTION

A virtual platform for facilitating processes and communication from the field, giving all relevant personnel the information they needed to respond to an event.

THE BENEFIT

A tool that allowed NEPPA to respond and coordinate quickly, minimzing damages from unexpected weather events.

veoci®

October 27, 2021 caught many Bay Staters by surprise. An unexpected nor'easter slammed into the Massachusetts coast and left almost 500,000 residents without power — and a mess for the state's utilities to clean up.

This nor'easter didn't bring the winter wonderland many expected. The storm instead delivered heavy rain and intense winds. Local news channels paid little attention to the looming storm, forcing residents and utility crews alike to react quickly.

The Northeast Public Power Association (NEPPA), a regional trade association based outside of Boston, supports nearly 80 utility members throughout New England from southern Connecticut to northern Maine. NEPPA provides a mutual aid program for its members as one of its primary services. Through the program, NEPPA coordinates crew assistance from neighboring utilities when other member utilities are impacted by significant weather events such as hurricanes or snowstorms. This October nor'easter was no exception.

"It was one of the worst storms affecting coastal Massachusetts since my involvement," David Ketchen, Assistant General Manager for Littleton Electric Light and Water Departments shared. "You can tell which storms are the worst just based on the mutual aid requests that come in. The requests came in consistently throughout the day, it wasn't just one quick pass. It was an all-day event as far as mutual aid is concerned."

The storm hit numerous regions within the NEPPA mutual aid network, demanding synergy among multiple different regional coordinators in order to best determine what resources went where. They all worked out of Veoci, a cloud-based emergency management platform, that acted as a central common space and database for users.

Ketchen explained that having everything in one software made it easy to quarterback, especially since all of the players were not just down the hall, but throughout New England. Utilities were able to request mutual aid with a click of a button. A simple digital form collected critical information and shared it with the appropriate coordinators.

Request information was fed into a centralized map view providing a visual representation of where aid was needed. Ketchen added that larger storms like this nor'easter necessitate cautious crew allocation, as crews should remain as local as possible. "We have 10 regional coordinators located in three different states responsible for coordinating NEPPA mutual aid for all of New England. Having one centralized location that all coordinators can reference when determining how to dispatch crews is vital and Veoci provides that."

Veoci helped coordinators track and close out each of the eight aid requests. Notifications also automatically alerted assisting utilities to their crews' returns. Dashboards played a key role in maintaining this common operating picture, as well as providing insight into response performance. According to Ketchen, "Being able to go back, review the analytics, and see how the day played out and how we can improve for the next large event ... this is so crucial."

The mutual aid network's response process and procedures did not drastically change with Veoci, in fact they are very much the same that they have always been. Veoci was not the saving grace of the day, that would be the hard work of all utility members of NEPPA. The software purely gave a collaborative working space that therefore increased communication and provided an aerial view of the event.

Although the next nor'easter may blow through with little warning, with the help of Veoci, the coordination of resources and effective mutual aid response will be no surprise.

For more information about Veoci's comprehensive suite of solutions, contact Ryan Nally, Veoci's General Manager of Utilities, at ryan.nally@veoci.com or 203-668-3272.

195 Church St 14th Floor, New Haven CT 06510 | 230-782-5944 | info@veoci.com | veoci.com

Undergrounding

What is it Worth to Your Community?

Installation

Quicker, less expensive construction

Underground installation estimated to be anywhere from 3-10x the cost to install overhead lines.
Recent projects from investor-owned utilities have estimated the cost to underground lines anywhere from $250,000 per mile to upwards of $3 million per mile.

Limitations

Not suitable for densely populated areas. Needs available right-of-way, clearance

Not recommended for rocky or overly sandy soil, areas prone to flooding, or with seismic activity

Lifespan

40 years

60 years

Hazards

Contact with trees, wildlife, damage in severe storms

Contact with wildlife, other projects requiring digging

Mai

Faults
easily

Repair
cost of
expens
and re
proper

In

3

g:

The cost of running power lines underground varies considerably – and comes down to more than just construction costs. Here is a rundown of the pros and cons – and factors affecting the cost equation – for overhead and underground power lines.

intanance

and other problems more detected and fixed — within hours

Safety

- Easily marked/visible in construction and repair work
- Reduces contact with downed wires, vehicle collisions with poles, fires

save our tress

Community relations

- Don't like look of poles and wires, tree trimming
- Don't want yard dug up, trees uprooted

rs can take days or weeks to fix, f repairs can be 5-10x more sive (from labor, equipment, eimbursement to rty owners).

Reliability

- Undergrounding in areas prone to damage (e.g., with higher outages by mile) can boost overall reliability. IOU Wisconsin Public Service saw a **97% reduction** in outages from undergrounding tap lines

a survey of public power utilities:

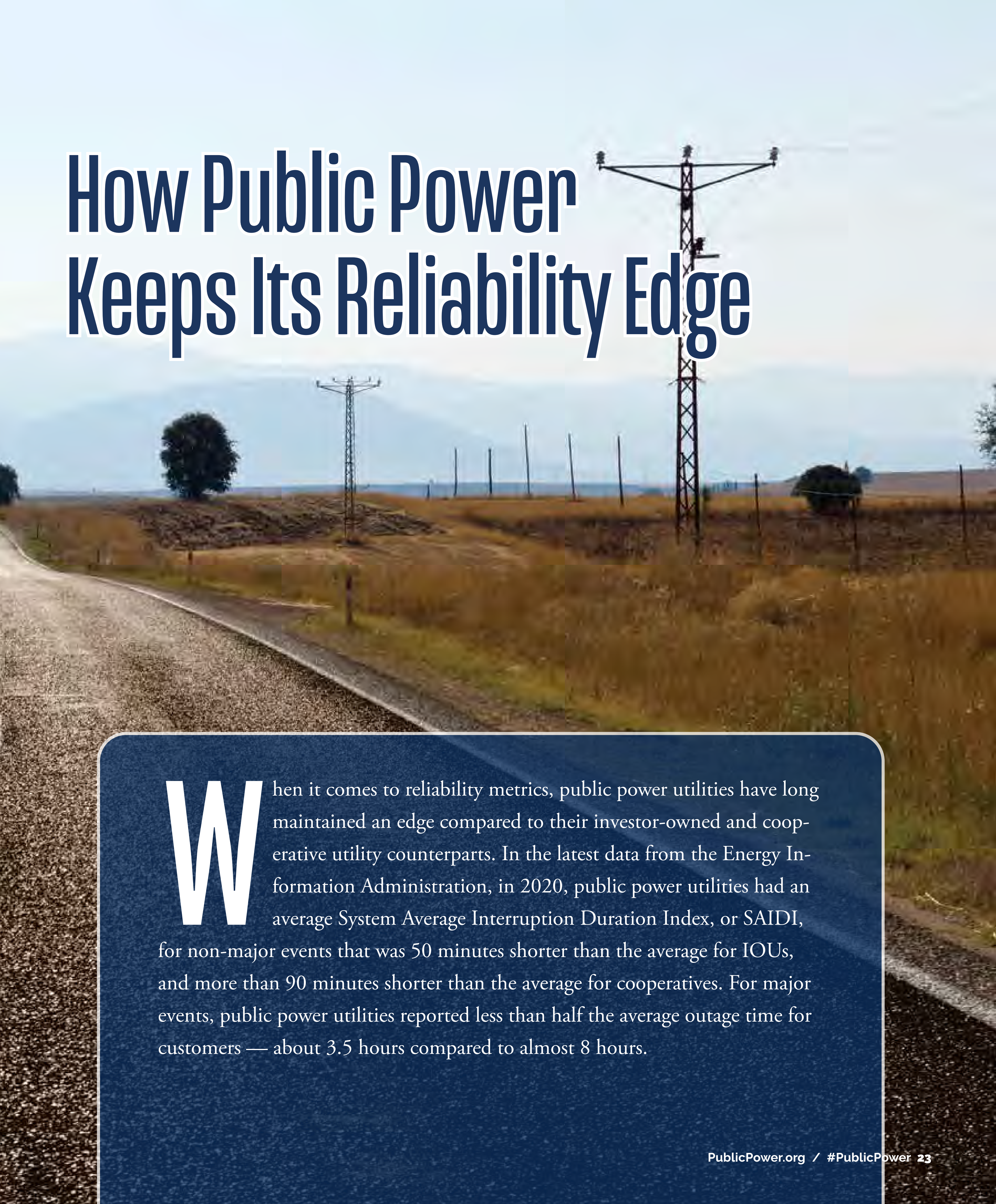
390 average underground miles

613 average overhead miles

38% require new construction lines to be underground

Your Trusty Neighborhood Utility:

By Susan Partain, senior manager, content strategy, American Public Power Association



How Public Power Keeps Its Reliability Edge

When it comes to reliability metrics, public power utilities have long maintained an edge compared to their investor-owned and cooperative utility counterparts. In the latest data from the Energy Information Administration, in 2020, public power utilities had an average System Average Interruption Duration Index, or SAIDI, for non-major events that was 50 minutes shorter than the average for IOUs, and more than 90 minutes shorter than the average for cooperatives. For major events, public power utilities reported less than half the average outage time for customers — about 3.5 hours compared to almost 8 hours.

Part of this is a matter of geography. A recent report from the Minnesota Public Utilities Commission regarding declining reliability at Xcel Energy went so far as to suggest that the IOU investigate selling portions of its service territory in southern Minnesota to neighboring utilities. The report noted that reliability was worse in the utility's rural areas, and that staff might have to drive for hours to even reach an outage location to perform necessary restoration work.

Aside from usually having smaller service territories, allowing lineworkers to quickly arrive on the scene for repairs, public power utilities take steps to keep their reliability edge — continually improving for their customers and preparing for the future.

The following reflections from public power utilities that have earned the eReliability Tracker Certificate of Excellence, awarded to utilities that subscribe to the service and fall within the top quartile for lowest average SAIDI over time, revisit how these utilities prioritize reliability.

Identifying Needs

According to Todd Dusenberry, assistant general manager at Vernon Public Utilities in California, an important start to ensuring the public power utility maintains its high standards is to track and measure the number of outages, the cause, and the duration. From there, the data helps the team to identify aging infrastructure and equipment and proactively develop a replacement program that helps the utility budget to minimize unanticipated large capital costs.

Although its service territory is only 5.2 square miles, VPU has a number of large commercial customers that run 24/7, so its peak load of approximately 200 megawatts is comparable to many of its neighboring publicly owned utilities. These customers can't afford extended outages, said Dusenberry. About half of the utility's outages are momentary, which VPU defines as lasting less than 10 seconds.

In the last few years, VPU has embarked on several efforts to improve system reliability, such as converting overhead distribution lines from 7 kilovolts to 16 kilovolts; installing high-capacity, steel-core-stranded overhead conductor wires; integrating mid-circuit automatic reclosers; and replacing a majority of its substation transformers. The majority of VPU's system is overhead, and most outages are mylar balloon- and bird-related, so the conversion from 7 kV to 16 kV creates larger spacing between conductors on poles, which, in turn, reduces the vulnerability of phase-to-phase contact and helps reduce the number of outages.

Replacing the lines is only one type of upgrade VPU has made. The utility has also added several technologies to boost its reliability.

"While all our distribution lines have automatic circuit reclosers, VPU has installed mid-circuit reclosers to further limit the impact of outages in areas with higher risk," said Dusenberry. "Additionally, we've reconductored our lines and installed aluminum conductor steel-reinforced cable so when there is an interruption on the line, it minimizes sustained outages and helps with restoration efforts."

Dusenberry also credited VPU's efforts to replace the majority of transformers at substations and an aggressive pole replacement plan with reducing outages related to aging equipment.

"The eReliability Tracker has been extremely helpful as it offers a level of automation, where we are able to easily input the information, the

tracker aggregates data, and then provides comparative analytics," he said. Having the comparative analytics allows VPU to identify efforts to proactively focus on improving system reliability. Prior to utilizing the eReliability Tracker, VPU was manually tracking stats on a spreadsheet and then receiving comparative data via a third-party consultant. Dusenberry noted that this data from other utilities was limited and took longer to access, which reduced VPU's ability to be responsive.

"It's not so much the data, but the ease with which you can extract it," he said.

The metrics VPU gets also help staff respond to customer inquiries within minutes, particularly from large commercial customers, who make up approximately 70% of its load. Staff can extract details on outages from the tracker to develop a reliability report on a circuit.

Relaying metrics to customers also means knowing what is meaningful to them.

"From a customer perspective, I have always found [customer average interruption duration index to be] an impactful metric. The amount of downtime is exactly what the customer remembers," said Kevin Sullivan, general manager at Ashburnham Municipal Light Plant in Massachusetts. The public power utility serves a primarily residential community of about 3,000 customers in the north central part of the state. "If [CAIDI] could be held to 60 minutes or less, I am pleased and have always found that the customer understands that an outage will happen, albeit infrequently."

"From a utility perspective, SAIFI provides me with a 30,000-foot view of outage that I can offer a comparative to by month, year, etc.," Sullivan added.

Staying Ahead of the Game

The City of Kirkwood Electric Department in Missouri is also proactively working to harden its distribution system to boost reliability. It identifies needs for system upgrades via analyzing its reliability data.

> “Tree trimming is without question the single biggest task for the greatest gain”

“It’s the analytic way of looking at things instead of firefighting, because we used to react and we knew the calendar. So, we’d say we’ve got to make sure we’re going to be available with crews and we have a mutual aid agreement — all the things that you would do to brace yourself and get ready for the inevitable,” said Mark Petty, director of the Kirkwood Electric Department.

But now, because Kirkwood Electric has the data associated with power outages, “the history of them, where they were located, what the causes were, we’re able to do proactive things,” he said.

Kirkwood Electric is able to have a capital program that “gets out in front of outages and does some things to try to slow them down or prevent the impact of the weather on us,” Petty said. First and foremost, the utility focuses on tree trimming.

He noted that during the pandemic, “we had to suspend a lot of our contractor access and operations just because we were trying to keep people safe.” Therefore, the utility was not able to work on things like the hardening of the distribution system and tree trimming. “It came back to haunt us in the hurricane season of June, July, and August of last year,” Petty said.

Starting in October 2021, personnel were deployed into the field and able to “do a lot of good tree trimming in particular,” so that by the time colder weather and snow arrived in early 2022, “we were able to have great reliability.”

“Tree trimming is without question the single biggest task for the greatest gain,” noted Sullivan. He said that Ashburnham Municipal Light Plant works with an arborist annually to provide a growth study and to ensure its trimming methodology is current.

Increased Technology

“Utilities must take every advantage possible to ensure reliability,” said Sullivan. “Reliability coupled with low rates and great customer service should be the hallmark of every public power utility.”

Being able to extract meaningful information about reliability often means needing to rely on an increasing array of technologies to provide enhanced data.

“You’ve got to be a smart utility. You’ve got to have that AMI system that gives you the information real time on your outages and then helps you to fold that in for your analytics later on,” stressed Petty. “You’ve got to have a GIS system. You’ve got to train your people to be able to use the analytics or the information. You get to those things — [and] that means you’ve been able to pivot from being reactive to starting to be analytical — and it certainly helps during outages.”

Embracing technologies, like drones and infrared camera imaging, has been an extremely useful tool for VPU, and it has used such technologies to conduct assessments and evaluations on electric infrastructure. Dusenberry credits such technologies as useful and effective for hard-to-access areas as they help to proactively identify potential equipment failures. VPU utilizes infrared camera imaging to visually inspect wires and substation conductors and equipment, and then the utility proactively replaces or identifies any equipment that shows signs of the potential for overheating for near-future replacement.

Taking advantage of this technology meant needing to train staff on how to fly a drone and obtain certification for infrared camera use. Moving forward, VPU is looking to outfit drones with infrared cameras to help elevate visual inspections and is installing automation equipment such as reclosers and converting equipment to smart grid applications.

"Vernon Public Utilities is always exploring technology that can improve our responsiveness, safety and reliability and connect with other APPA utilities to learn about what has helped in their service territories," added Dusenberry.

He mentioned that as a smaller utility, having auto reclosers tied to SCADA helped to enhance efficiencies. Having such data easily accessible across the utility helps not only with identifying and resolving any issues, but also in letting business customers know in a timely way the likely duration of any outage and what steps are being taken toward a resolution.

Technology, such as auto reclosers, and simpler tools, such as wildlife fault protectors, could be helping to lower the incidence of outages public power utilities see that are caused by a common nemesis: squirrels. Data from the eReliability Tracker from 2017 to 2021 shows that the average rate at which public power customers experienced squirrel-caused outages in 2021 was lower than in each of the preceding years in 10 out of 12 months of the year. The average rate of 1.4 squirrel-caused outages per 1,000 customers in 2021 was the third-leading cause of outages, behind tree-caused outages and utility maintenance and repairs.

RISE OF THE MACHINES:

AUTOMATION AND ARTIFICIAL INTELLIGENCE IN UTILITIES

BY SUSAN PARTAIN, SENIOR MANAGER, CONTENT STRATEGY, AMERICAN PUBLIC POWER ASSOCIATION

As electric utilities continue to modernize and evolve along with technology, an increasing focus is on how the electric grid can use automation and artificial intelligence within operations, particularly to help with the growing complexity within the distribution system. The two concepts are often intertwined, and certainly can be, but there is an important distinction.

Artificial intelligence is about training machines to aid in tasks such as learning and decision making – often at a scale and pace beyond what is capable for humans.

Automation is about making systems and machines be able to operate or perform certain functions without human intervention.

For utilities, AI might be used to cull through data from equipment sensors and pull out patterns or trends for utility workers to take note of in regards to needed maintenance. Automation, on the other hand, would be setting up devices on the system such as reclosers or switches that self-trigger when certain criteria are met. Both rely on human input and design to get established, and therefore are subject to flaws.

A number of technologies allowing for automation have been available to utilities for decades, including automated meters, reclosers, and switches. However, this availability has not always translated to adoption – whether because of cost or other resources needed to deploy the technologies. In the American Public Power Association's 2020 Distribution System Reliability and Operations Survey report, only about 30% of respondents reported having automated switching in place. And while the Energy Information Administration reports that more than 70% of all electric customers in the United States are now served by advanced metering infrastructure, just over half of public power customers are connected to smart meters.

MOVING TO AUTOMATION

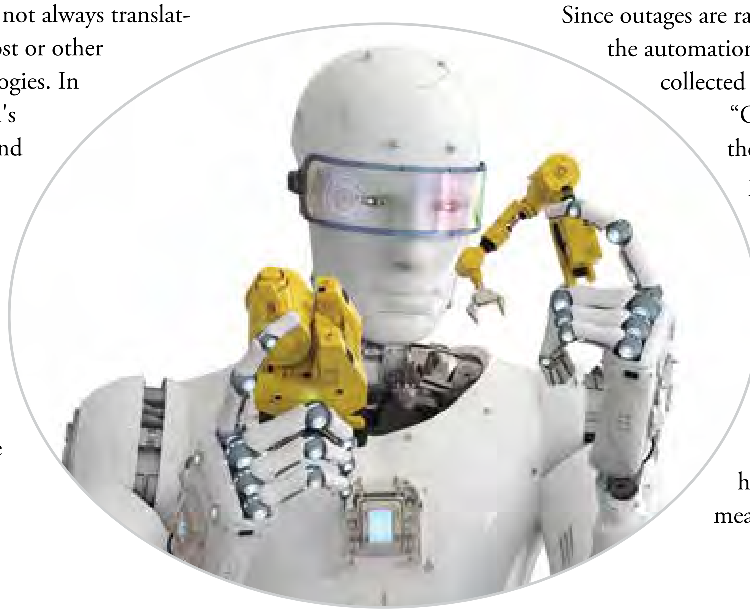
The electric department for the city of Leesburg, Florida began its foray into automation a decade ago as part of a larger transition to smart grid technologies. While working on various smart grid upgrades, the team singled out the need to upgrade the systems aging feeder breakers, and thought they'd give automation a try.

That decision led to the installation of automated reclosers on a section of four feeders that formed a ring bus around one of the commercial areas in the city. The city engaged ABB to provide the reclosers and other equipment needed to establish the automation, including customizing a fault detection, isolation and restoration, or FDIR, logic.

Steven Davis, Leesburg's electric service planner supervisor, noted how setting up the system required close coordination between line crews and ABB to figure out the system, which he said was a first for both ABB and the utility. There had been some skepticism on the team about implementing automation, given that earlier iterations of automated technology were viewed as not working very reliably. For the roll out, a lot of testing was done at night, said Davis, so that crews could see exactly how the system worked – and that it worked – and to run through what they would need to do in terms of any related safety protocols.

Since implementing the system, Davis said there have been a few times when the automation kicked in, and that it helped improve recovery time for the sections that weren't affected. He also mentioned how switching can be achieved more quickly and easily, and requires involving fewer field personnel. "Everything had already been swapped out and switched out before the crews could even make it on site," he said. "So all they had to worry about was that one section that was still out."

Since outages are rare events, the day-to-day benefit of the automation comes from the data that can be collected more easily from the system. "Our operations folks really like having the automated reclosers out of high points and mid points so that number one we can look at the loads," said Davis, mentioning that the loops include some large subdivisions in its territory. "Having that data coming in, we use it quite a bit in trying to balance the loads on the feeders. Being able to look at some real time measurements instead of having to send crews out and get those measurements."



The two initial loops where the automated reclosers were added constitute about 20% of Leesburg's load. Davis said the utility has continued to add more automatic reclosers to midpoints at each of the five substations on Leesburg's system, and for about half of its feeders. The reclosers can be controlled from the operations center, which helps personnel to better monitor load and allows for real-time communication with the reclosers and to see faults as they happen. And having the detailed data on the load patterns has been helpful in planning more accurately for new construction in the area.

With the communication technology that supports the feeders now outdated and no longer supported by ABB, the crews that manage the substations are reviewing other options for being able to keep the automatic restoration as part of the system design. The utility is looking at enhancing the communications on the system, either by adding fiber cable, enhanced cellular networks, and upgrading the radio system.

FOCUSING ON HIGH-USE AREAS

When Lakeland Electric, the third-largest public power utility in Florida, looked to begin implementing a distribution automation scheme on its system, it decided to focus on the Publix Manufacturing Center, a high-use area within its system that was already served by its own substation.

The distribution automation system uses a real-time automation controller and automated reclosers that are connected via a high-speed fiber optic system. Lakeland Electric personnel worked with Schweitzer Engineering Laboratories, which developed the equipment, on the system specifications and programming required to get the automation correct.

Before implementing the automation scheme, Lakeland experienced fault conditions that resulted in power outages across multiple zones, which affected multiple manufacturing centers across its territory. Now, should a fault occur within the manufacturing complex, the system can quickly isolate only the faulted section and maintain power to the remainder of the complex. This setup results in minimum power disruption to the other centers and to the system overall.

The system is designed so that distribution relays are programmed to coordinate timed overcurrent elements with downstream recloser controllers. The distribution relay trip logic contains phase and ground time overcurrent, instantaneous overcurrent relay elements, as well as trip commands received from the automation controller. The real-time automation controller relies on several programmed equations to determine the appropriate relay response, which depends on the status of the tagging relay and reclosing shot bit.

Scott Fowler, manager of substation operations at Lakeland Electric, noted that implementation of the distribution automation system has allowed Lakeland to improve its reliability and overall availability to the manufacturing center, and allows for rapid fault isolation if and when faults occur.

Fowler said that the system equipment, which has been in place since 2011, is now somewhat obsolete, so staff will soon need to reprogram and replace the system using Schweitzer Lab's current "standard libraries."

ARTIFICIAL INTELLIGENCE GETS REAL

While more nascent than automation technologies, utilities have already begun to explore and deploy AI for a variety of uses. Applications within more traditional utility operations range from helping to do speedy and deep analysis of drone imagery to conduct more thorough inspections of assets and predict imminent failure of equipment to helping system operators better manage and balance assets from a growing array of distributed energy resources and renewable sources. This can predict future output and forecast demand more accurately based on a wide set of factors.

AI can also potentially help save lives, not just time and effort. The Electric Power Research Institute recently studied whether tools such as natural language processing and machine learning could conduct meaningful analysis of utility incident and injury reports to find any common precursors to events that cause more serious injury, leading to more lost workdays and to fatality. EPRI researchers compiled data from eight utilities with their Occupational Health and Safety Database, providing the AI with 100,000 records spanning 26 years of incidents. The analysis identified the top serious incident and fatality precursor conditions, which included tree trimming and falling from heights, so that utilities could cross compare this data with safety programming and protocols to bring down risk of injury among workers.

Outside of direct grid operations, AI could also help utilities to better understand and break down customer usage trends and needs to identify who would benefit from specific programs and incentives, or analyze customer service calls and correspondence to alert utilities to patterns that customers might be dissatisfied. The former would require utilities to install smart meters that can identify usage at the appliance level.

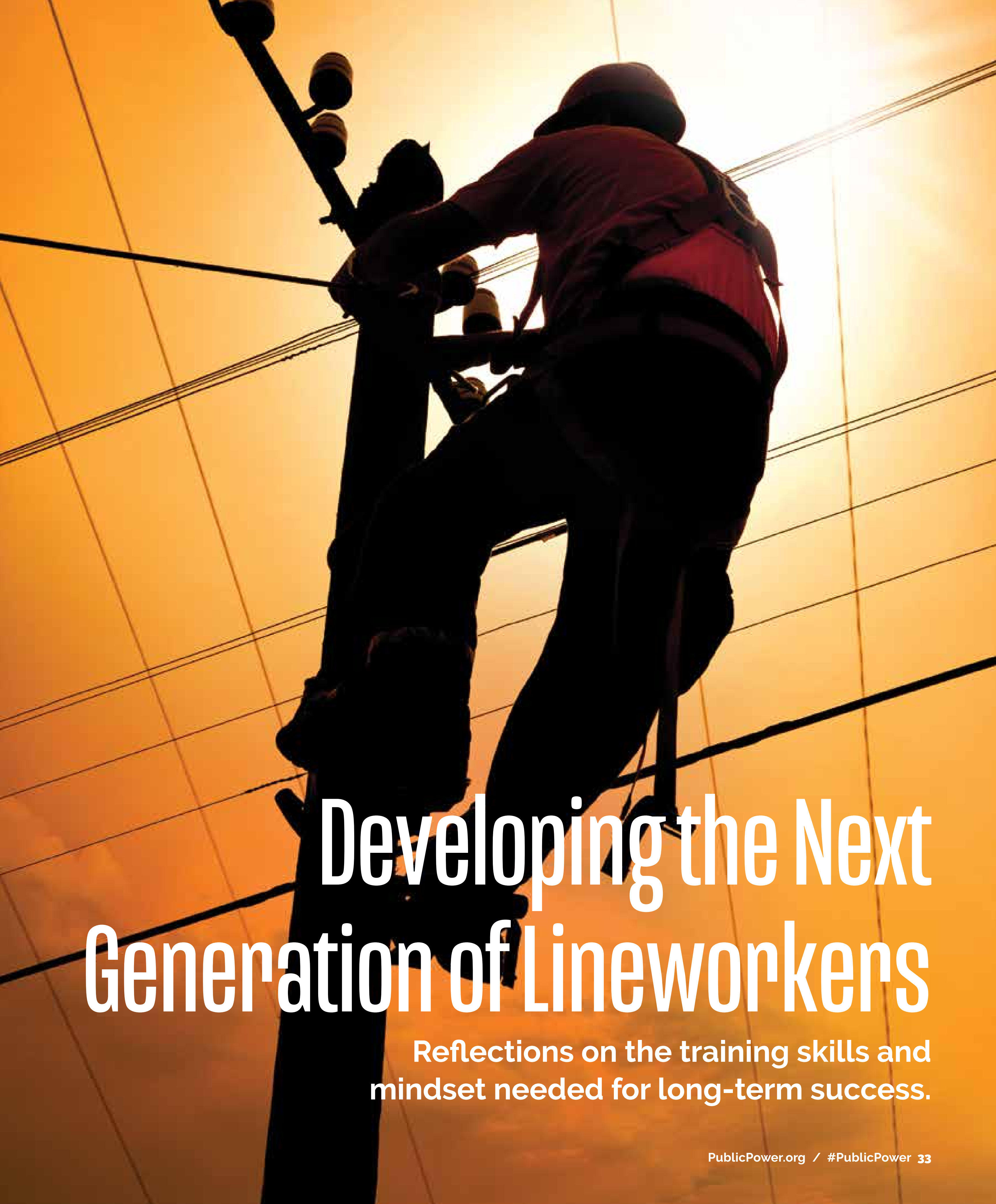
Given the upfront investment needed to deploy technologies that support AI, and the reality that AI offers a better return when it can pull from a larger data set, smaller utilities might be dissuaded from exploring any machine learning applications. When weighing the tradeoff in cost versus savings to make it worthwhile, utilities might want to explore the potential for taking smaller steps to test the concept, so that they don't find themselves completely behind the curve or left behind compared to their peers when any such practices become the norm.

Beyond simply keeping up with the industry, weighing the cost of deploying AI-driven technology requires a long-term assessment on how such a system might impact anything from rate design to infrastructure investments to future load.

Perhaps one of the stronger arguments for utilities investing in systems to crunch customer data from AMI revolves around transportation electrification. This is because the overwhelming majority of electric vehicle charging occurs at drivers' homes. Utilities are not only in the best position to capture and make sense of this charging behavior data, but are also in the position to potentially suffer most from the inability to predict or influence load fluctuations from EV charging. This usage will be highly variable based on the specific community's characteristics – including average commutes and typical housing types. Even if a utility has only a handful of EVs within its community, getting a foundation for understanding the local patterns will help utilities to be better assured and prepared if and when adoption expands.

The potential for return on investment is more difficult to calculate when it comes to AI applications in customer service, but there is value. Utility leaders, particularly in public power, are likely keenly aware that customers can make decisions about how much power they use – and how trusting they are of adopting additional electric end-uses – based on their experiences with the utility. The utility holds sway over how much a customer sees value in acquiring energy efficient appliances, handles home heating and cooling, and in acquiring any assets for backup power. So as homeowners start to make long-term decisions that affect the electrification of their homes (or transport), which will ultimately influence the utility's future load growth, getting trust now will be paramount. Further, a PricewaterhouseCoopers analysis found that customer satisfaction is necessary in getting rate increases approved.

The nature of a changing industry is that the historical data we have might not be as helpful in identifying patterns for the future. When it comes to AI and automation, the important focus is for continual learning – whether that's the people or the machines.



Developing the Next Generation of Lineworkers

Reflections on the training skills and mindset needed for long-term success.

Skilled trades are in high demand, and electrical lineworkers — the people on utility front lines who install, and repair the lines and equipment that make up the visible aspects of a utility's distribution system, are no exception. The Center for Energy Workforce Development estimates that in the next few years, the need for lineworkers will surpass 16,700 individuals. Fulfilling this need is not just a matter of finding the warm bodies to go into the job, but recruiting those with the right mindset and training them to be able to do the job safely and effectively.

The people involved with training public power lineworkers shared their reflections on the apprenticeship and training process.

What apprenticeship training entails – and how it has changed

Apprentice training is a multi-year endeavor representing extensive skills development across many areas.

ElectriCities of North Carolina offers a hybrid in-person and online apprenticeship training program. The online component includes four levels, each with about 20 learning modules, or courses. The in-person component consists of two week-long trainings that focus on safety. Participants also must complete 2,000 hours of on-the-job training for each level and have a supervisor attest that they are meeting performance requirements.

Craig Batchelor, manager of safety and training at ElectriCities, shared how the training evolved from what had been a solely in-person program, which consisted of four week-long training sessions. Batchelor also touted a learning management system that allows students to share updates and track progress online.

Danette Scudder of the Tennessee Valley Public Power Association, which offers a four-year apprenticeship program, noted that while TVPPA has taken advantage of new technologies to supplement traditional instruction, such as using virtual reality simulations, participants find the instructor-led, hands-on training to be the most effective way to learn the material.

Mike Willetts, director of training and safety at the Minnesota Municipal Utilities Association, echoed the value of in-person instruction. MMUA's four-year apprenticeship program also combines an online curriculum with hands-on training that students attend at least four times per year. "The training facility provides an outstanding opportunity for the students to concentrate on technical projects in a protected environment. Students can gain valuable insight on how other utilities may approach a similar situation, plus make valuable connections with other lineworkers and industry suppliers," noted Willetts.

During these trainings, topics cover everything from electrical theory to proper use of tools and personal protective equipment; safety protocols; construction and maintenance of poles, circuits, and insulated equipment; and more.

Mastering new skills

Scudder shared that recent years have seen discussion topics added at all levels of training around becoming more familiar with distributed energy resource technologies, including troubleshooting and dealing with backfeeding from such assets.

"As the field progresses, a higher level of understanding of new DER-related technologies will be key as more public power systems begin to see these various technologies deployed," she added.

In North Carolina, Batchelor mentioned a shift to making lineworker training more "all-encompassing," with added modules on substations and meters. He noted how ElectriCities offers trainings and connections to subject matter experts that support worker development at any level, as lineworkers also benefit from developing leadership and communication skills. Yet, he noted, the apprenticeship training is about starting with the basic linework skills – including safety, electrical theory, climbing, and proper use of tools.

"Having a solid understanding of basic electrical theory; hazard recognition; and proper use of personal protection equipment would be at the top of my list," said Willetts.

"Apprenticeship is a small piece of developing good quality linemen. Most of that is done at home," said Batchelor.

Mindset needed

"It is important that every apprentice understands that it takes time to be a skilled journeyman lineworker. You have to do the work. It can't happen overnight," said Willetts. He went on to call out six attributes of people best suited to be a successful lineworker:

- Be willing to learn
- Have a good work ethic
- Enjoy working outside in all conditions
- Attention to detail
- Enjoy working as a team and helping others
- Understand that linework is more than "just a job"

Batchelor stressed that lineworkers need to be open-minded and flexible.

"For a young apprentice it is essential that he or she maintain a positive attitude, willingness to accept instruction, ability to work as a team, and finally physical ability to perform the job," said Scudder. "A general openness to change will be pivotal as the trade is undergoing dramatic changes in how a lineworker conducts their daily work."

Scudder added that outside of formal training, utilities can foster on-the-job learning opportunities through formal mentorship programs.

Getting students interested

Willetts stressed that public power utilities can do a better job of engaging young people in middle school and high school about the array of job opportunities in public power – including beyond linework. He noted that utilities can host projects, contests, and events in schools to raise this awareness.

In Ohio, Cleveland Public Power looked to how it could teach high school students about linework to confront the dual challenges of an aging workforce within the public power utility and a concern about "brain drain" from the city. CPP started an internship program in 2008 in which students from the Cleveland Metropolitan School District get both classroom instruction and supervised on-the-job training to learn skills associated with becoming lineworkers – including safety protocols, CPR, customer service, and earning a commercial drivers license.

Beyond learning how to drive commercial vehicles, students show an interest in what it takes to restore power in the city, including seeing how the dispatch center operates. CPP works with school guidance counselors to recruit graduating high school students into the paid internship, which is designed to prepare students to enter apprenticeship programs and includes mentorship opportunities.

Since starting the program, the utility has evolved instruction to include distinct tracks and added opportunities to learn other skilled positions, including electric transmission operators, and cover topics including financial planning.

A Refresher on Reducing Distribution System Loss

BY NATHAN MITCHELL, SENIOR DIRECTOR, OPERATIONS PROGRAMS, AMERICAN PUBLIC POWER ASSOCIATION

At every stage of the electric system – from the generator to the outlet – there are energy losses. This inefficiency has a price: When energy is lost, utilities must generate or purchase additional energy to meet demand. Efficiency isn't just about cost – it is also a gauge of system performance, and monitoring items such as excess heat from transformers can support increased reliability.

Some system losses are inevitable, and loss cannot be eliminated altogether. Almost two-thirds of energy is lost in the generation and transmission of electricity. At the distribution level, most losses occur in lines and regulators (about half of losses) and transformers (about 27%). Losses in other devices, such as switches and breakers, typically make up a lower portion of losses but might be significant in system secondaries where currents tend to be high.

Here's a brief refresher on ways that public power utilities can work to reduce losses throughout the distribution system.

Calculating Loss

A simple way to calculate the cost of losses is by multiplying the average cost of energy per megawatt-hour by the total energy losses. Another way is to find out the utility's loss percentage, which is the ratio of total energy losses to total sources of energy. The median loss percentage for public power is 4.07%. Losses of more than 6% for public power utilities may suggest excessive physical losses.

Reducing Conductor Losses

Refurbishing or replacing old conductors is an important loss reduction technique and can provide increased capacity on the system. Conductors allow the flow of electrical current. Conductors also offer resistance to the flow of current, which results in power loss. The loss of power (in watts) is represented by the familiar relationship:

$$P = I^2 R$$

The current carried by the conductor in amperes (A) and the electrical resistance in ohms (Ω) are symbolized as *I* and *R*, respectively.

Resistance, *R*, for a conductor is determined by the following equation:

$$R = \frac{\rho L}{A}$$

The resistivity of an object is represented by ρ (rho) and is measured in Ω m (ohmmeters). *L* represents the length, and *A* represents the cross-sectional area of the material. Resistance increases with the length of the conductor and decreases with the cross-sectional area of the conductor. Just as more water can flow through a wide pipe compared to a narrow one, electrical charge is higher and resistance is lower on wires with greater cross-sectional areas.

The following example shows how reconductoring older #4 AWG copper conductors to newer 336.4 kcmil 26/7 aluminum and steel conductors can reduce line losses by a factor of nearly five.

Conductor	Stranding	Circular mils	Allowable Ampacity	Resistance ohms/mile	Line losses for 100 Amp load at the end of a 1-mile line
4 AWG	Solid	41740	170	1.314	13.14 kW
336.4	26/7	336400	510	0.273	2.73 kW

While reconductoring is theoretically a great option for reducing losses, the process, including new hardware, is costly – and can be constrained by disruptions in the supply chain for certain materials.

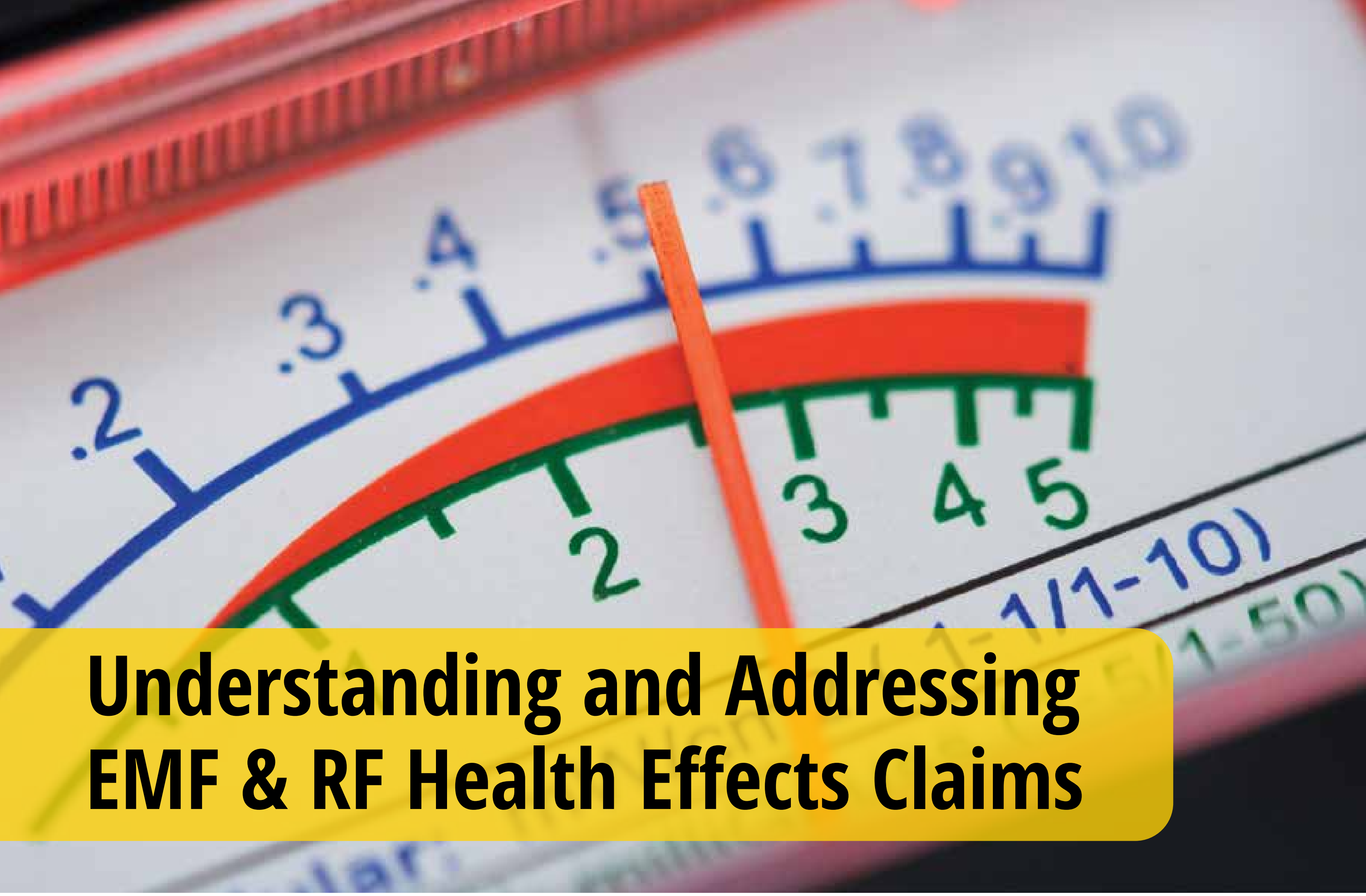
Other Ways to Reduce Loss

Regularly examining system performance, and having an accurate picture of load factor, can help utilities to pinpoint problem areas and prioritize upgrades based on biggest cost of loss. When current supply chain constraints ease, utilities can deploy strategies such as building in guarantees against transformer loss values to purchase agreements with manufacturers, such as by requiring expanded testing for large lots of transformers or on-site visits by utility personnel during manufacturer testing, or price adjustments for transformers not meeting the guaranteed loss performance.

There are many more ways to measure and reduce distribution system loss – some which are easier to implement and others which are associated with higher expenses.

- Maintain balanced currents on all three feeder circuit phases as much as is practical.
- Keep secondary circuits as short as possible.
- Use the smallest capacity transformer feasible for each installation, considering factors such as ambient temperature during peak load, duration of expected peak load, and expected load growth.
- Evaluate the benefits of three-phase versus single-phase construction; avoid using voltage regulators downstream from the substation where possible.
- Ensure all abandoned transformers have been disconnected from the primary line.
- Analyze capacitor banks to verify that capacitor size and location are properly matched to feeder load.
- Check every meter multiplier recorded on the billing system against the corresponding multipliers marked on the meters every two years.
- Perform regular meter testing and calibration. Test single-phase customer meters every eight years, polyphase meters every six years, and high-use meters annually.
- Install substation metering/supervisory equipment for each feeder to obtain profiles of voltage, current, and power factor versus time.
- Convert long, substantially-loaded single-phase circuits to three-phase.
- Convert feeders to a higher voltage level.
- Re-conductor the trunks of heavily-loaded circuits, beginning at the source end.

Increasing efficiency helps to continue to keep public power's edge in reliability and affordability compared to our peers. Utilities with outstanding energy efficiency efforts should consider applying for the Smart Energy Provider designation.



Understanding and Addressing EMF & RF Health Effects Claims

Activists and some members of the public use claims of health effects from electric and magnetic fields (EMF) to oppose new utility facilities. In the last decade, claims have spread to include newer technologies that use radio frequency fields (RF), such as utility smart meters and 5G antennae mounted on utility poles. A utility that is the source of these exposures which raise health concerns – particularly about the health and safety of children – cannot long maintain its credibility if it does not communicate effectively with the public about those health concerns.

The nature of the claims

Public concerns about EMF and RF most often focus on childhood leukemia, adult cancers, neurological disorders, and human reproduction and development. Claims are also made about loss of productivity in dairy cattle, threats to the well-being of other farm and domestic animals, risks to wildlife, and damage to property values.

These health risk claims can have significant consequences for utilities. Recently, a large transmission project was rejected by regulators in the face of strong public opposition based on alleged EMF health risks and damage to property values. Another project near a school had to be withdrawn by the utility's CEO after claimed EMF health risks galvanized community opposition. Other utilities have faced significant delays and/or costly changes to projects in order to address EMF or RF concerns.

What studies show

There are thousands of studies on EMF and RF. Every year several hundred new studies are published in scientific journals. This large body of research has been evaluated many times by mainstream public health authorities, such as the US National Cancer Institute and the World Health Organization, which have concluded that the science does not demonstrate a causal relationship between EMF or RF and any illness or disease.

Nonetheless, there is a great deal of misinformation about EMF and RF health risks online. There are scientists and medical doctors who claim there are many studies showing associations with health risks and adverse biological effects that lead to diseases such as cancer. Activist groups, such as the BioInitiative, claim that the scientific research demonstrates that EMF and RF exposures are "known" causes of cancer. Others interpret the International Agency for Research on Cancer classification of EMF and RF as "possible" causes of cancer in humans as showing there is a recognized and established threat to health.

What utilities can do

There is no single approach that will fit all, but utilities can help themselves by getting into position to respond promptly and effectively to public questions and concerns about EMF and RF exposures. This means keeping informed about the steadily growing body of EMF and RF research, knowing what the public health authorities and the activists are saying about health risks, being ready to address new studies that attract public and media attention, and developing accurate, defensible and persuasive messages about EMF and RF issues.

Utilities should regularly evaluate and update information about EMF and RF health issues to make sure it is accurate and defensible. A utility's specific response and communication on this topic will vary based on community needs and what technologies are being deployed, and can include talking points, printed materials, materials on its website, and in direct communications with customers.

In recent years, many utilities have had a loss of institutional knowledge about EMF and RF issues. This creates a potentially significant liability exposure when EMF and RF issues arise and the utility does not have the experienced people needed to provide a prompt and reliable response. Community questions about EMF and RF health issues have escalated from concerns to controversy and acrimony when members of the public believe the utility response was inadequate, uninformed, dismissive, incorrect, or misleading. Missteps in these interactions can lead to community opposition to utility facilities, which in turn can result in expensive delays or changes to proposed projects, and in some cases, costly litigation.

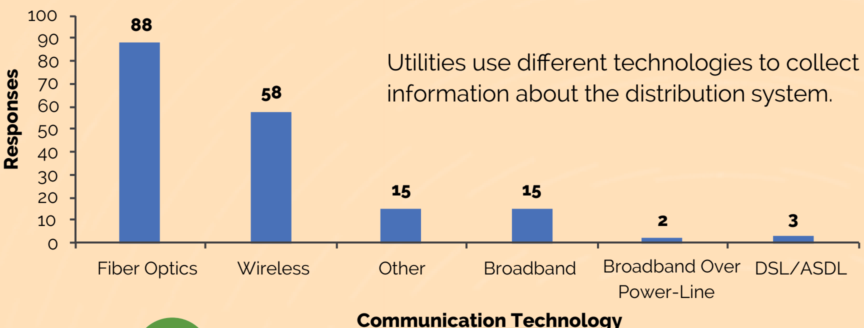
About the authors: Tom Watson and Curtis Renner of Watson and Renner regularly advise and counsel electric utilities about EMF and RF and health effects issues, and have represented them in regulatory and court EMF and RF litigation since 1980. They are also legal counsel to the Utility Health Sciences Group (UHSG), an industry-wide organization dedicated to providing its members with the knowledge they need to address EMF and RF health issues responsibly. An APPA representative serves on the UHSG Steering Committee and several public power utilities are members of UHSG. For more information about UHSG, contact one of the authors (tw@w-r.com or crenner@w-r.com).

Public Power Practices for Reliable Distribution Systems

Public power utilities are known for being reliable. This reliability comes from how they design, manage, and support the local electrical distribution system. The following highlights from the 2020 Distribution System Reliability and Operations Survey Report showcase how public power utilities approach several aspects of operations.

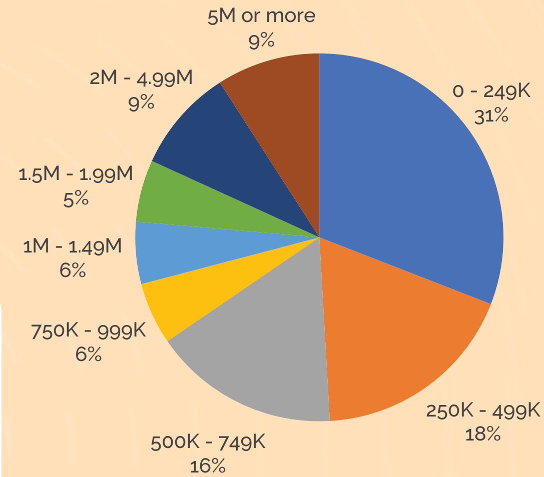
Maintaining Reliability

Most utilities track reliability system-wide (84%), and many also track reliability indices by feeder (68%) and by substation (43%).



Utilities use different technologies to collect information about the distribution system.

Tree trimming is the most common outage prevention practice.

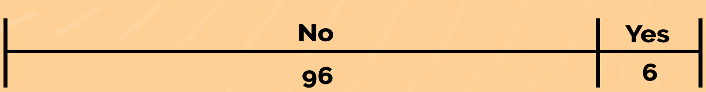


Of utilities who shared annual tree trimming cost, about half spend less than $500,000, and 20% spend $2 million or more.

Addressing Power Quality

Despite increased adoption of renewables and distributed energy resources, most utilities aren't seeing any related power quality issues.

Has your utility experienced any power quality challenges when integrating renewables or distributed generation sources in the last three years?



Staffing

The overall average is for about one full-time equivalent lineworker per 1,000 customers served.

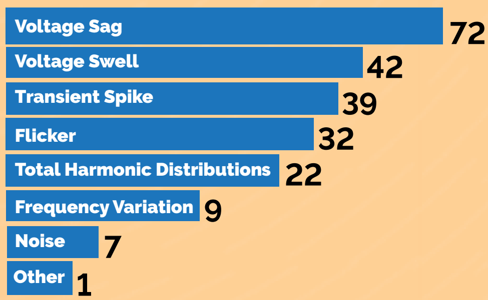
For 4,000 customers, the average utility employs:

2.5 journeyman **one apprentice** **one contracted lineworker**

Staffing also varies based on territory size, but on average, utilities employ about one lineworker per square mile.

The biggest power quality concerns utilities report include voltage sag, voltage swell, and transient spike.

Power quality concerns



Explore more practices in the 2020 Distribution System Reliability and Operations Survey Report, available at www.PublicPower.org/Reliability.

CONGRATULATIONS

Congratulations to the 2022 Reliable Public Power Provider (RP3) program designees. We salute your commitment to operating at the highest levels of reliability, safety, workforce development, and system improvement as you build and support strong public power communities.

DIAMOND

Austin Energy, TX

Austin Utilities, MN

Blue Earth Light and Water, MN

Bristol Tennessee Essential Services, TN

Bryan Municipal Utilities, OH

City of Georgetown Energy Services, TX

City of New Bern, NC

City of Troy, AL

City of Wadsworth Electric and Communications, OH

Columbus Light & Water, MS

Fayetteville Public Works Commission, NC

Gainesville Regional Utilities, FL

Grand River Dam Authority, OK

Holland Board of Public Works, MI

Huntsville Utilities, AL

JEA, FL

Lexington Utilities, NC

Marshfield Utilities, WI

Moreno Valley Utility, CA

New York Power Authority, NY

Owatonna Public Utilities, MN

Ripley Power and Light Company, TN

Rochester Public Utilities, MN

Silicon Valley Power, CA

Vernon Public Utilities, CA

Zeeland Board of Public Works, MI

PLATINUM

Anderson Municipal Light and Power, IN

Brookings Municipal Utilities, SD

City of Leesburg Electric Department, FL

City of Mount Dora Electric, FL

GEUS, TX

McMinnville Water & Light, OR

Middleborough Gas & Electric Department, MA

Modesto Irrigation District, CA

Moorhead Public Service, MN

Richmond Power & Light, IN

Saint Peter Municipal Utilities, MN

Snohomish PUD, WA

Sterling Municipal Light Dept., MA

Town of Front Royal, VA

Waupun Utilities, WI

GOLD

City of Jackson, MO

City of Newton, NC

City of Winfield, KS

Cleveland Public Power, OH

Fort Valley Utility Commission, GA

Hurricane City Power, UT

Ipswich Electric Light Department, MA

PES Energize, TN

Plymouth Utilities, WI

Rolla Municipal Utilities, MO

Town of Clayton, NC

Utilities Commission, City of New Smyrna Beach, FL

Washington City Power Department, UT

RP3 RELIABLE PUBLIC POWER PROVIDER

American Public Power Association