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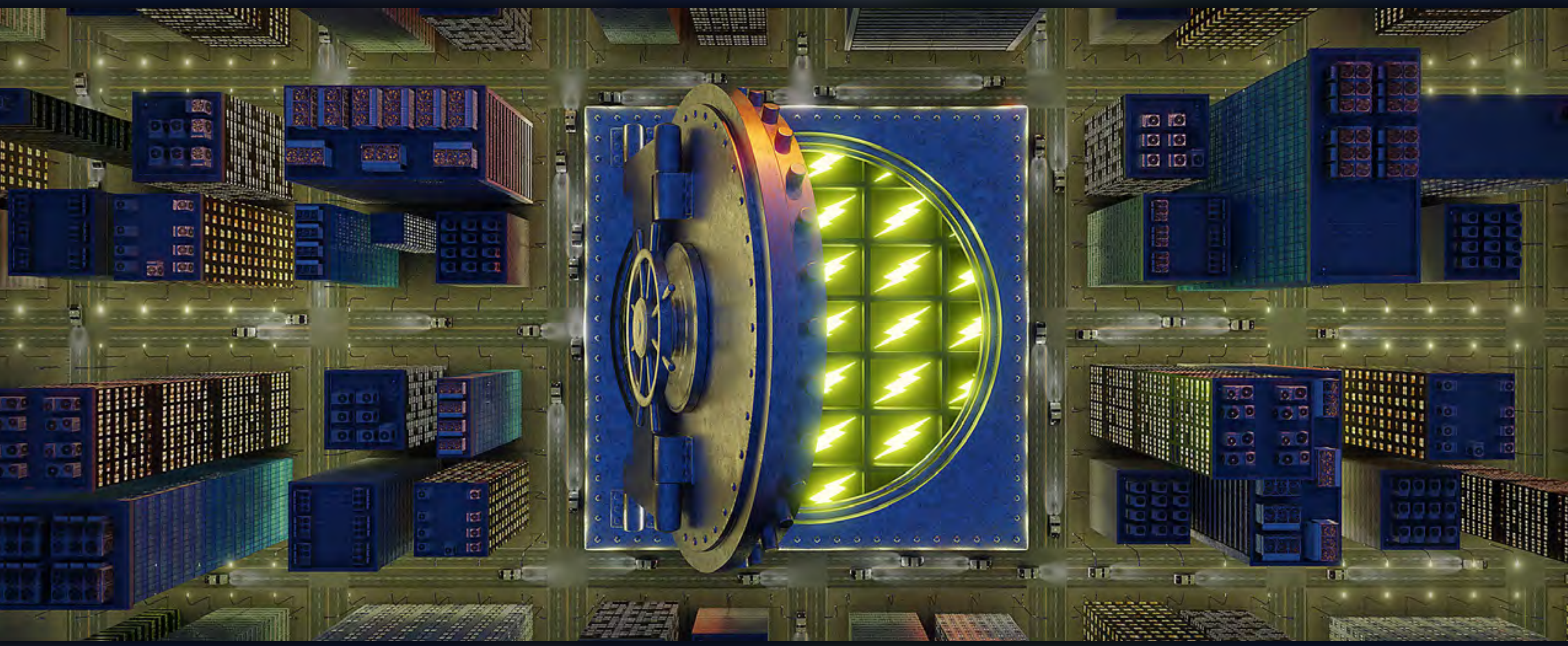
Energy Storage to Count On



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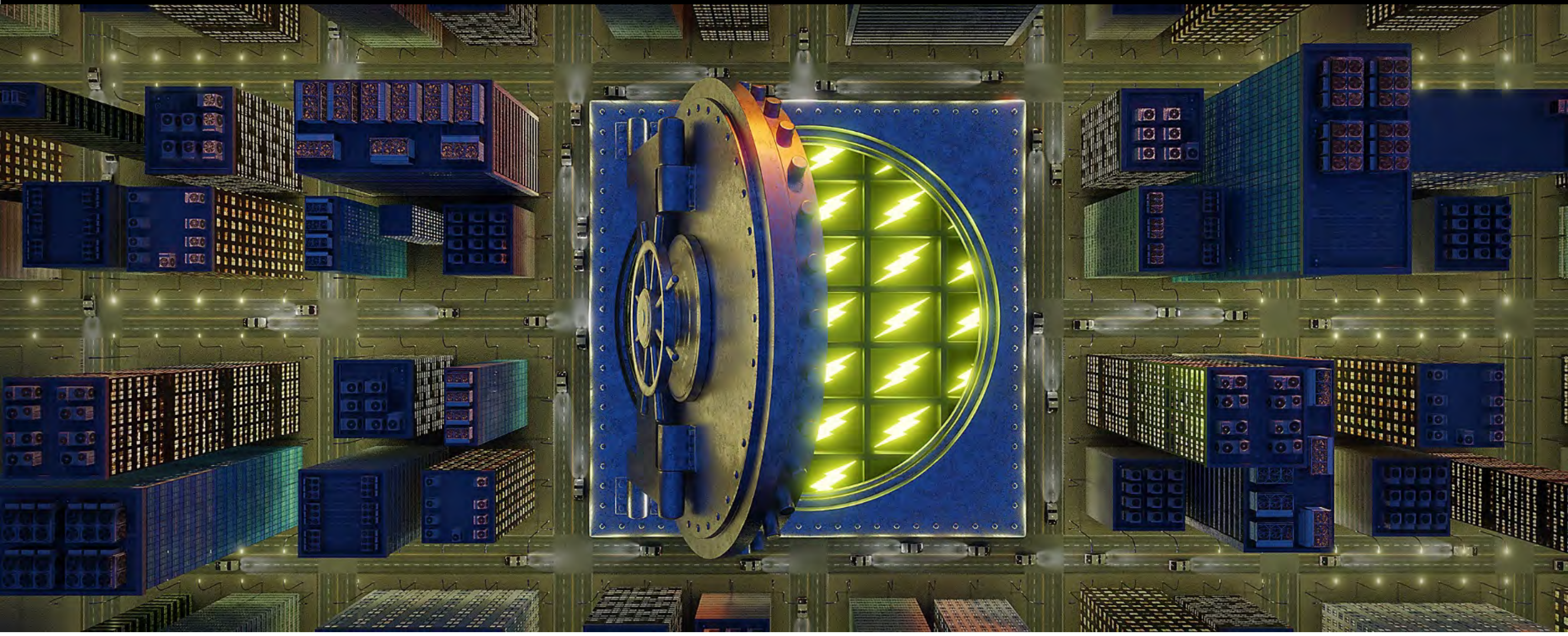


Energy Storage to Count On

In Separate Studies, EPRI and NERC Highlight Areas of Concern Regarding Long-Term Battery Performance and Reliability

By Chris Warren

At the end of 2020, 12 states had goals to achieve 100% renewable or net-zero emission electricity generation. The states vary in geography, climate, and population, ranging from Maine in the northeast to Louisiana in the southeast to California in the west and the Hawaiian Islands in the Pacific. And it's not only states making deep decarbonization commitments. Nearly 300 large corporations have made a pledge to go 100% renewable, and a number of utilities, like Xcel Energy, Dominion Energy, and the Sacramento Municipal Utility District (SMUD), have committed to net-zero electricity.

The blueprint for achieving these ambitious clean energy targets varies from state to state and organization to organization. But they all share a common feature: energy storage will play a prominent role. With so much intermittent wind and solar generation being added to the grid, storage is critical for maintaining reliability.

Grid-scale batteries are being increasingly deployed. According to Wood Mackenzie, 3.5 gigawatt-hours of battery energy storage were installed across the United States in 2020. For context, in the prior six years, a total of 3.1 gigawatt-hours of battery storage went into operation. Most of this growth was due to large-scale systems deployed by utilities.

The increasingly important role battery storage is expected to play in the power system of the near- and longer-term future raises important questions about the technology's performance and reliability. Utilities, regulators, and other industry stakeholders are looking for assurances that they can count on these assets to perform when they're needed, especially in the absence of a significant track record.

"We anticipate storage is going to be a bigger and bigger part of our operations," said Steven Baxley, research and development manager for Southern Company. "Battery storage projects have so far been mostly pilots, but we are on the cusp of beginning commercial projects on the regulated and wholesale sides of our company. We want to understand whether the systems perform according to our specifications long term, whether they will be reliable, and what O&M (operations and maintenance) issues may be of concern over time."

There may very well be reasons for concern. An initial EPRI analysis of battery performance metrics reported by manufacturers has revealed some discrepancies. While these discrepancies don't immediately affect the ability of storage systems to deliver vital services, they may have significant impacts on their long-term performance.

EPRI DELVES INTO PERFORMANCE AND RELIABILITY

For the past three years, EPRI has been working to investigate the performance of batteries deployed in the field as part of its Energy Storage Performance and Reliability Data Initiative. During the recently completed first phase of research, EPRI monitored and collected data on numerous battery storage systems deployed in different locations, ranging in power capacity from 6 kilowatts to 1 megawatt. The systems were intended for various applications, such as residential and utility substation support. All the systems—with the exception of one vanadium redox flow battery system—are lithium ion batteries, the predominant technology being installed across the world today.

To assess energy storage performance and reliability, EPRI tracked two critical metrics and compared them with values reported by the manufacturers. One metric, state of charge, is the remaining capacity in a battery expressed as a percentage of its fully charged capacity. An accurate measure of a battery's state of charge is essential, because it indicates whether the battery can deliver the energy, flexibility, and reserves needed by grid operators. For example, the state of charge measurement tells an operator if a storage system has enough energy to compensate for potential drops in wind and solar generation—a common and expected scenario in power systems with a high penetration of renewables.

Accurate measurements are also needed so that storage systems can be reliable participants in wholesale electricity markets, which have high performance standards. In addition, they can inform grid planners on the extent to which storage systems may help reduce peak demand and thereby avoid investments in powerlines, transformers, and other traditional grid infrastructure.

The second energy storage metric, state of health, is a measurement of system degradation. It is commonly expressed as the maximum state of charge available in a system at a particular time relative to its original capacity. As lithium ion battery storage systems are charged and discharged over time, their available energy capacity decreases, and their efficiency declines. Storage operators need accurate state of health data to determine whether their assets are performing to their specifications, associated performance guarantees, and warranty commitments. Accurate data also informs planning for maintenance, battery replacements, and other downtime.

"When manufacturers sell storage systems, they provide performance and lifetime expectations, but these may differ from actual performance because of unexpected degradation in real-world conditions," said Steve Willard, an EPRI technical executive leading the Energy Storage Performance and Reliability Data Initiative. "Accurate state of health measurements over time can help storage owners and operators get ahead of unexpected changes in performance."

DISCREPANCIES IN BATTERY PERFORMANCE METRICS

On the surface, the state of health and state of charge metrics may appear straightforward, similar to a fuel gauge or odometer on a vehicle. But they are not as simple. The state of charge of a lithium ion battery can't be measured directly and instead must be estimated by measuring parameters like voltage, temperature, and current. Similarly, the state of health is rarely measured directly. Standard testing approaches take the battery out of operation, fully discharge it, and then recharge it. By measuring the energy that enters and leaves the battery during the discharge and charge cycle, it's possible to quantify the battery's remaining energy capacity. Many owners and operators may not be able to collect such measurements at regular intervals, because they need their storage systems to deliver certain benefits. EPRI plans to develop and test methods that owners and operators can use to estimate state of charge "on the fly."

Battery operating systems continuously report state of health and state of charge values to owners, but the vendors of these systems often don't explain how they are calculated. "They are coming up with these values within a proprietary black box, and we don't know what they are assuming," said Willard.

After monitoring the storage systems deployed in the field for three years, EPRI found some notable discrepancies between the values it calculated and the values that the vendors were reporting. For example, one of the systems under investigation operated for a year and a half while regularly reporting that the state of health was 99.5%. EPRI's measure was 96.5%, which translates into a degradation rate that is seven times faster and a lifetime that is potentially many years shorter. Additionally, EPRI research has revealed that battery systems have displayed state of charge values that fluctuated faster than is physically possible.

A MOVE TOWARD STANDARDS

There is consensus among utilities, regulators, and other power industry stakeholders that such discrepancies are problematic, given the prominent role storage is expected to play in grid operations and electricity markets. Indeed, a recent report on grid-scale energy storage by the North American Electric Reliability Corporation (NERC) highlighted a lack of uniformity in storage performance data as a key challenge. As an important first step toward addressing this challenge, NERC and the Institute of Electrical and Electronics Engineers (IEEE) are developing standards and guidelines for reporting storage metrics.

EPRI's research findings, field data, and approaches to assess state of health and state of charge are informing these standards. An expanded EPRI database of information on the performance of storage systems operating in the field can inform the standards as well. EPRI also worked with Sandia National Laboratory to develop a guide about the performance and reliability data that could inform relevant standards and procurement specifications.

Standards for reporting performance data are not new in the electricity sector. For decades, NERC has required operators of traditional electric generating equipment such as transformers, circuit breakers, and fossil fuel-powered generators to report performance data through a program called Generating Availability Data Systems (GADS). "A working group develops reporting standards, and NERC has a database where asset owners and operators have to report metrics—such as forced outage rates—that show how well the asset is running," said Willard. "NERC recently developed reporting requirements for wind generators, and they're about to finish developing requirements for big solar PV farms."

EPRI is expanding its storage performance database by incorporating data from national laboratories, universities, utilities, and other institutions. "We need a lot of data for robust independent verifications of the metrics reported by vendors," said Willard.

EPRI researchers are also developing tools that storage owners can use to assess system degradation and performance as well as report equipment failures and the amount of time it takes for repairs. The idea is to enable owners to conduct these assessments without having to take their systems out of normal operation. The tools draw on the latest research and powerful computational techniques. Last fall, the Energy Storage Integration Council, EPRI's open industry collaborative forum, released a publicly available tool that supports uniform data collection for tracking storage operational activities.

"When a system fails, operators often have to wait weeks for the vendor to come and repair it," said Willard. "Deploying a megawatt-scale storage system can cost millions of dollars, and taking it offline for a few days can mean a significant loss in value. These delays are reflective of a nascent market."

As utilities deploy more storage around the world, they need more real-world performance data.

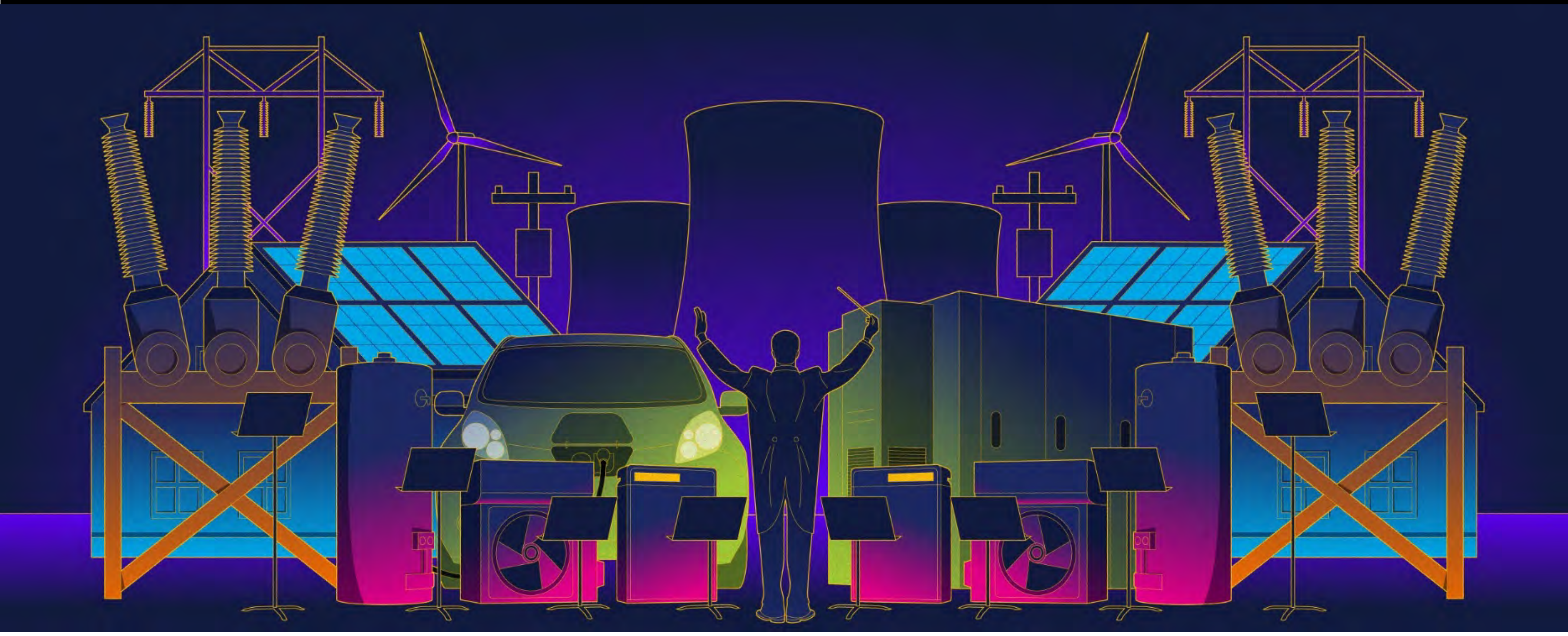
"We are eager to learn how these systems will operate and perform in terms of degradation and reliability in different conditions," said Baxley. "Our wholesale business will operate some systems in the desert of California, and our regulated business is planning systems in the Southeast. We want to understand any differences in performance in these regions with different conditions. As we move toward the renewable future everyone is envisioning, it's critical to know if storage is reliable."

Energy Storage Integration Council

EPRI established the Energy Storage Integration Council (ESIC) to advance the deployment and integration of energy storage systems through open, technical collaboration. EPRI convenes and coordinates ESIC's working groups and informational sessions and publishes its documents and online resources. Over ESIC's eight-year history, more than 2,500 people have participated, and about a dozen publications have been released. Meetings are open to the public.

KEY EPRI TECHNICAL EXPERTS

Steve Willard, Joseph Thompson, Peggy Ip,
Michael Rosen



Envisioning the Grid of the Future

Grid Modernization is an Exceedingly Complicated Endeavor That is Redefining How Utilities Operate

By Michael Matz

Chris Campbell may have one of the most challenging jobs at Salt River Project (SRP), a utility that provides power and water to more than two million people in central Arizona. One of Campbell's responsibilities as SRP's senior director of distribution and telecom operations is to manage the utility's distribution grid modernization initiative. This 10-plus-year undertaking, known at SRP as the Distribution Enablement Program, aims to advance dozens of new capabilities critical to grid planning and operations. SRP's future grid will rely on numerous technologies that are not all mature today, so Campbell's team needs to assess when to deploy them at scale across the grid. What's more, many companies, universities, and other organizations want to partner with SRP to help develop new grid technologies.

"There are so many technologies and partners to get our hands around that we needed a way to ground and prioritize all these things," said Campbell.

SRP's solution was to develop standard procedures, methods, and milestones to guide the design and implementation of all pilot projects, field demonstrations, lab studies, and other research. The utility also standardized procedures for deploying and scaling new technologies broadly across the grid and incorporating them into grid operations and planning. This R&D pipeline, which SRP calls the Distributed Resource Integration Value Enhancement (DRIVE) program, also defines processes for prioritizing research and documenting lessons learned and insights. A key part of DRIVE is a new technology innovation laboratory that enables staff to set up and test equipment. Prior to the launch of DRIVE, each research activity was managed independently, with no clear connection to strategy or priorities and no consistent knowledge transfer approach.

"This pipeline is helping us to organize the chaos," said Campbell.

THE WHY AND HOW OF GRID MODERNIZATION

SRP's effort to redefine the way it conducts research and scales technologies reflects a broader trend in the electricity sector: as grid modernization initiatives proceed around the world, utilities are making fundamental changes in their business operations to manage the enormous task effectively.

Numerous factors are driving utilities to develop multi-year grid modernization initiatives. The frequency of extreme weather is growing. The number of grid-connected distributed energy resources is accelerating, and utilities need to integrate them into grid planning and operations. To build a more flexible, reliable, and resilient grid, utilities are investing in more advanced technologies, such as distribution automation and operating systems that enable more awareness and control of the distribution grid and connected devices. Many of these technologies are still emerging, and their performance is not well understood.

During the last two years, nearly every U.S. state has launched regulatory or legislative efforts related to modernization. In addition to national emissions goals, many states and jurisdictions have established targets for greenhouse gas emissions, renewable energy, and energy storage. Customers expect more from utilities, including personalized services, real-time information on outages, greater resiliency, and the ability to install smart appliances and easily connect solar, energy storage, and electric vehicles to the grid.

"Many modernization initiatives today involve a fundamental change in how grids are operated and planned," said Don Von Dollen, an EPRI expert on grid modernization who has helped more than two dozen utilities develop and refine their modernization strategies. "Every utility will have a different vision of what a modern grid is as well as a different strategy and pathway for realizing that vision."

Grid modernization is a complicated endeavor, requiring robust strategic plans and substantial, well-defined, and carefully coordinated investments sequenced over many years. It can potentially involve numerous utility departments, including generation, transmission, distribution, customer service, asset management, workforce management, and information technology. While adding new capabilities, utilities must continue to deliver low-cost, reliable electricity.

There are many potential pitfalls. While a technology might hold promise, deploying it while it is still maturing or before it is needed can lead to higher costs and poor performance. For example, a distributed energy resource management system (DERMS) may become necessary as utilities consider ways to integrate increasing numbers of distributed energy resources into their grids. By tracking and testing DERMS technology as it matures and by learning from peer experience, utilities can be better positioned to apply lessons learned and support a more successful deployment when they need it.

INTEGRATED PLANNING AND GOOD COMMUNICATION

For SRP, a key driver of grid modernization is the rapid growth of solar, electric vehicles (EV), and other distributed energy resources connected to the distribution grid, all of which can result in more dynamic demand, supply, and power flows. In SRP's service territory, there are currently about 30,000 customer-sited rooftop solar systems with a total capacity of about 276 megawatts. SRP expects this number to grow dramatically over the next decade. In addition to rooftop solar, SRP has 648 megawatts of utility-scale solar power online or contracted and under development, with a goal of 2,025 megawatts by 2025. Most of this will be connected to the transmission grid, though some may connect to the distribution grid. While about 18,000 of the three million vehicles in SRP's territory are currently electric, the utility has a goal to manage charging for 500,000 EVs by 2035. Increasingly, SRP's distribution control center will need to manage these resources while maintaining the safety, reliability, and resiliency of the grid.

Like many utilities, SRP has faced the challenge of how to coordinate grid modernization across different company departments. SRP's Campbell is responsible for developing and updating a distribution grid modernization roadmap, which is a timeline of specific actions needed to achieve various new grid capabilities. In parallel, other SRP departments—such as transmission, customer programs, generation, and resource planning—each have their own modernization roadmaps, all of which need to be integrated into a coherent company-wide effort.

"Historically, these groups planned independently, but we know that this initiative can't be managed in parts and pieces," said Campbell. "A key is to have a holistic and integrated process. I spend a lot of my time aligning staff around all the pieces that need to come together."

According to Campbell, SRP created a new "integrated planning process" consisting of numerous staff from different departments that serve as facilitators, with an aim to build relationships across departments and develop a company-wide integrated system plan. Because technologies, grids, and customer needs are changing rapidly, modernization roadmaps change every year, and integrated planning can help the departments adapt to the changes quickly. "These facilitators are reinforcing the importance of working together and are building a new culture," said Campbell.

Indeed, EPRI's Von Dollen has observed from his work with utilities how essential it is to have extensive collaboration among departments. "An investment in a new capability in one department could have beneficial applications in other departments," said Von Dollen. "A utility may miss an opportunity to reap the full benefits of investments when one department develops a modernization plan without adequately engaging with other departments."

According to SRP's Campbell, because modernization is likely to impact the daily details of grid operations in a significant way, it's important to involve grid operations staff in the development of a modernization vision and implementation plan. "At the end of the day, these are the people who will be implementing these changes," he said.

For Campbell and his team, effectively communicating their modernization vision has been an important part of gaining support for it at all levels of the company. "Grid modernization is a tremendously complex problem to solve, and the solution will be complex," said Campbell. "To help people across the company understand these issues, it's important to use simple terms to explain the changes and how they align with corporate strategy and a roadmap of actions."

"PREREQUISITES" FOR THE FUTURE GRID

Campbell points to another approach SRP has used to integrate modernization initiatives across the entire company. The utility has pursued what he calls "foundational" capabilities and investments that are essential to enable the many advanced capabilities of the future grid. "These are the prerequisites for modernizing our grid," said Campbell.

One foundational area is developing standards for data so that different departments can analyze the same data to yield information and insights. For example, because both customer relations staff and grid operations staff rely on customer data to do their jobs, putting the data in a standard format helps to integrate these teams.

"Good data is critical for everything we do," said Campbell. "Our grid planning group recently implemented a new load forecasting tool that draws on customer, weather, economic, and other types of data. Good data standards were essential in the success of this project."

As part of another foundational investment, SRP has spent the last three years updating its geographic information system (GIS) to provide more complete, accurate, and timely data. This will enable a new advanced distribution management system (ADMS) that incorporates DERMS to aggregate, track, forecast, and control the output of large numbers of distributed energy resources. "The ADMS will allow us to manage grid voltage and power quality in a future grid with a more dynamic supply and demand of energy," said Campbell.

SUPPORTING UTILITIES IN THEIR MODERNIZATION JOURNEYS

EPRI offers a range of services to support utilities in developing their grid modernization strategies, using an approach that deconstructs modernization into smaller pieces that can be easily evaluated and then reconstructed into an overall plan. Over the last 15 years, EPRI has worked with more than two dozen utilities on their grid modernization strategies, building a deep understanding of what makes modernization successful.

“Our approach makes a daunting task much more manageable,” said Bruce Rogers, another EPRI expert on grid modernization.

A modernization strategy includes a detailed set of objectives, a list of new capabilities needed to achieve the objectives, and roadmaps to acquire the capabilities. Examples of objectives are integrating distributed energy resources, reducing the number of outages, enhancing customer experience, and maximizing workforce productivity and safety. Capabilities are tools, technologies, processes, and expertise associated with operations, planning, grid infrastructure, monitoring, communications, cybersecurity, the customer, and much more. Examples include planning models, generation forecasting for distributed solar, augmented reality tools for field workers, and customer behavior analytics.

EPRI uses a systems engineering approach to synthesize the specific capabilities and technologies needed by a utility, leading to insights on their interdependencies and the timing and pace of their deployment. An example of the interdependence of technologies: the benefits of sensors and other measurement devices on the grid may be limited if they are deployed without the necessary communications networks and data management systems. A systems engineering approach may also lead to deployment strategies that begin with simpler solutions followed by more sophisticated approaches. The final product of EPRI’s analysis is a cohesive, comprehensive strategy.

“We have observed that the objectives and capabilities vary widely among utilities depending on what is driving them to modernize their grids,” said Rogers. “For example, we worked with one utility that focused on integrating solar, while another company prioritized managing and integrating EVs. A third company identified asset management as a top objective because aging equipment is impacting grid reliability.”

In 2019, SRP asked EPRI to conduct a formal assessment of its modernization roadmap. “Our CEO wanted an independent third-party assessment that could be presented to our board,” said Campbell. “It’s easy to get stuck in doing things a certain way. EPRI challenged us to look at our roadmap in different ways.”

Drawing on their experience working with other utilities on grid modernization, Von Dollen and Rogers provided SRP with feedback on its strategy, its planned pace of deployment, and how its roadmap compares with other utilities’ roadmaps. In addition, dozens of EPRI and SRP technical experts met to closely examine 10 technical areas, identifying areas in need of further development.

Rogers and Von Dollen host a monthly webcast series for utilities to present their modernization strategies and roadmaps. They have recently published a guide on developing a company-specific modernization strategy.

KEY EPRI TECHNICAL EXPERTS

Bruce Rogers, Don Von Dollen

EPRI JOURNAL

The Age of Customer-Sited Energy Storage is Approaching

Distributed Energy Storage Offers Big New Opportunities for Utilities, Customers, and the Grid

By Michael Matz

A key objective for Joana Abreu in her job as demand response program manager at Eversource is to find ways to reduce the utility's peak load. "Ten percent of the hours of the year account for 40 percent of the load in our service territory, and those 10 percent happen in the summer," said Abreu. "By reducing these summer peaks, we can limit the amount of fossil fuel-powered generation capacity that we need to bring online—and help reduce greenhouse gas emissions."

While her objective to reduce peaks is typical among utility demand response managers, Abreu is taking a notably novel approach to achieve it. She manages a program that pays incentives to homeowners and businesses for allowing the utility to use energy stored in their battery systems at times of high demand, targeting that critical 10% of hours. The program, called ConnectedSolutions, has had success in reducing peaks. For example, during a heat wave in July 2019, Eversource requested energy from its entire portfolio of customer-sited storage, helping to prevent outages and avoiding the need to bring more fossil fuel generation online.

Current enrollment is 687 residential storage systems with a cumulative capacity of 2.5 megawatts and 11 commercial and industrial systems totaling 9.6 megawatts. In the summer, homeowners receive $225 per average kilowatt for allowing Eversource to use the energy stored in their batteries during as many as 60 three-hour, high-demand periods. A typical home battery could contribute as much as 5 kilowatts per event, earning $1,125 for the season. Businesses receive $200 per average kilowatt, which means that a larger storage system contributing an average of 100 kilowatts could make $20,000 for the summer. According to Abreu, Eversource determined these incentive levels based on the expected cost savings from not having to purchase additional generation capacity on the wholesale energy market. Long term, Eversource may explore the use of storage for targeted dispatches at the substation level to relieve local areas of high demand.

NEW STORAGE BUSINESS MODELS FOR UTILITIES

With accelerating deployment of customer-sited, behind-the-meter storage, Eversource is one of a growing number of utilities investigating various ways to use these systems to support grid operations. More than 12 gigawatt-hours of behind-the-meter storage systems have been deployed globally, accounting for about half of all energy storage connected to the grid. According to Wood Mackenzie, 60 gigawatt-hours of global behind-the-meter capacity is expected by 2025. For context, that's about the same amount of electricity that was sold in Maryland in 2019.

More frequent fires, hurricanes, and other extreme weather are driving greater customer interest in resilience and on-site, backup power. In fact, a desire for uninterrupted power during outages is one of the most common stated reasons that homeowners purchase battery storage systems, according to Michael Norbeck, director for grid services business development at Sunrun, the largest installer of residential solar/storage systems in the U.S.

In addition to peak demand reduction and backup power during outages, customer-sited storage can provide a broad range of grid services, including energy to compensate for dips in solar and wind power production, energy arbitrage, frequency regulation, voltage support, and deferral of grid infrastructure upgrades. Relative to front-of-the-meter storage, customer-sited storage can potentially offer more cost-effective grid services because it is located closer to where many grid problems may emerge, such as overvoltage and an imbalance of energy supply and demand.

New business models are unfolding. In 2020, FERC approved Order 2222, which allows distributed energy resources like solar-plus-storage systems to participate alongside traditional generation resources in wholesale energy markets. Companies that provide solar-plus-storage systems to customers can aggregate these resources into fleets and receive compensation in energy markets for grid services.

> Interested in learning more about how integrators are working with utilities to tap the value of solar and energy storage? Join the "Raising the Bar on Resilience" session during EPRI's virtual electrification forum, A Net-Zero Energy System for All, June 28-30, 2021.

"Utilities can explore these new business models to benefit both their distribution and transmission operations," said Nick Tumilowicz, an EPRI expert on grid integration of battery storage and other distributed energy resources. "Utilities already engage with their customers in various ways such as helping them make their homes more efficient. If they want, they can begin engaging with their customers to tap the value of their storage systems. By putting these flexible resources to good use, they can reduce costs for grid operations and for their customers."

According to EPRI's Tumilowicz, utilities are evaluating several approaches to manage customer-sited storage, each with different advantages and disadvantages. One option, owning and operating storage systems, enables utilities to have full control over systems for grid services and build on existing customer relationships. The utility would need to configure the systems so that customers could still use them for backup capacity in case of an outage. While this option offers potential for a utility to include storage systems in its rate base, it may present regulatory constraints. "Regulated utilities are not allowed to own and operate certain types of assets, including storage, though this may change over time in different regions," said Tumilowicz.

A second option for utilities: customers own the storage systems, with the utility aggregating them via its control systems. "With this option, the utility has to invest in software and hardware to set up in-house aggregation capabilities," said Tumilowicz. "The utility can have considerable control over the storage assets, though less control than if it owned the systems. There may be fewer opportunities to cultivate customer relationships and less potential to capitalize the assets."

Under a third option, the utility purchases aggregation services from a third-party company, which can provide grid services upon request. While the utility does not need to invest in in-house aggregation capabilities, this option may offer limited control over storage assets, even fewer opportunities to cultivate customer relationships, and little opportunity to recover costs. By avoiding investments in physical assets and aggregation capabilities, utilities can potentially reduce costs for their customers.

Eversource's ConnectedSolutions program uses the third approach, working with its customers' aggregators, which include more than a dozen companies. Eversource schedules the events, during which its Distributed Energy Resources Management System (DERMS) communicates with the aggregators' control systems. The aggregator notifies customers of events by email and text 24 hours in advance. Some aggregators allow their customers to opt out of events by responding to these emails and texts.

According to Eversource's Abreu, Eversource intentionally opted not to serve as the aggregator. She explained that existing aggregator companies already have relationships with customers focused on offering a suite of options and applications to optimize their battery systems. Participation in Eversource's demand response program is one of many possible applications, such as continuous power during outages, energy arbitrage, and consumption of solar power generated onsite. "We see our role as narrower than an aggregator's," said Abreu.

AGGREGATORS: POTENTIAL UTILITY PARTNERS AND COMPETITORS

Storage aggregator companies are pursuing many different types of grid-related business opportunities. Sunrun, which has deployed about 16,000 residential solar-plus-battery storage systems in the U.S., offers a good case study. On its website, the company describes itself as a potential utility partner and provider of grid services to build a more resilient grid.

"We're looking for commercial opportunities where we have concentrations of storage assets," said Sunrun's Norbeck.

Sunrun works with Eversource's ConnectedSolutions program, fulfilling the utility's requests to discharge power to reduce peak load. In late 2020, Sunrun signed a deal with Southern California Edison (SCE) to deploy thousands of home solar-plus-battery storage systems that can be bundled as a 5-megawatt "virtual power plant" for grid services. In addition to using the virtual power plant to address high-demand periods and other grid events observed today, Sunrun and SCE are investigating how the plant could be used to mitigate other grid scenarios that SCE expects to see in the future, such as the threat of rolling blackouts during summer heat waves.

In 2019, Sunrun won a bid in ISO-New England's wholesale energy market to provide 20 megawatts of aggregated solar-plus-storage systems. The bid is an example of where an aggregator could potentially become a competitor to utilities and other power companies that also bid to sell electricity and related products on wholesale markets.

In partnership with Autogrid, an energy management software company, Sunrun is investigating ways to optimize how different batteries in a large portfolio respond to a request from a grid operator. Norbeck offers an example. "Let's say the utility wants one megawatt of energy for four hours outside of peak demand, and we have a portfolio of 1,000 batteries," he said. "We may be able to fulfill the request using just 750 of them, so which 750 should we use? We can consider factors like the state of charge of the batteries, which retail electricity tariffs participating customers may be on, and which customers indicated a preference that their batteries only be discharged during peak periods when they receive financial incentives."

What can help utilities and aggregators effectively collaborate on efforts to support the grid with the use of customer-sited storage? "It's important to provide enough compensation to encourage more storage deployment, which can in turn make storage more valuable to the grid," said Norbeck. "Also helpful are clear, consistent, and achievable performance requirements and a range of opportunities for storage to support the grid."

EPRI RESEARCH: FIELD DEMONSTRATIONS, PRODUCT TESTING, MODELING, AND MORE

When it comes to tapping the value of customer-sited storage systems, a big knowledge gap is standardizing how they connect to the grid and communicate with utilities. Standard, secure communications among utility, aggregator, and customer-sited systems is key to extracting value from storage, yet communication protocols are still governed by several different standards. EPRI is developing best practices intended to safely interconnect storage systems in a standard way so that they respond reliably to utility signals. Plus, EPRI researchers plan to develop open-source, standard communication protocols.

"In addition to deployments by big national integrators, mom-and-pop shops install a significant number of solar-plus-storage systems, many of which are connected to the grid and communicating in non-standard ways," said Tumilowicz. "National and regional integrators are deploying a heterogeneous fleet of storage systems with various makes and models, posing a challenge for utilities to execute standardized, cost-effective programs to use these assets. Six different batteries may speak six different languages."

EPRI is supporting utility demonstrations to test various storage applications in the field. For example, EPRI worked with SCE and Meritage Homes to design a residential neighborhood of 20 zero-net-energy houses in Fontana, California. They investigated several uses for the batteries deployed in 9 of the houses. For example, they configured the battery storage systems to absorb excess solar power in the early afternoon and power the houses during peak demand in the late afternoon and early evening to minimize use of grid electricity during that period.

"As with our other battery field demonstrations, our objective in Fontana was to optimize the batteries for the customers' benefit first, then looks for ways to benefit the grid, and finally examine how to maximize benefits for both customers and the grid," said Tumilowicz.

EPRI has provided design guidance and data analysis for Georgia Power's Altus at the Quarter, a neighborhood of townhomes equipped with rooftop solar, battery energy storage, and energy-efficient building components and appliances such as heat pump water heaters. Grid-interactive control systems manage and optimize all these devices. Georgia Power, EPRI, and other project partners are examining how all these devices work in concert to provide value to customers and the grid.

Other EPRI research on customer-sited storage includes:

- **Markets and deployment**: Reporting on storage technologies and tracking deployment of storage regionally and globally
- **Business models**: Evaluating new utility programs that aim to use storage for grid services
- **Technology and product testing**: Field-testing the capabilities and performance of storage products when grid-connected and aggregated and in different weather conditions
- **Economic valuation**: Developing tools and conducting economic modeling studies to assess the value of storage to customers and the grid based on factors such as location, capabilities, and electric rates

"More utility customers want resilience and backup power, and third-party companies are serving that demand by installing batteries at homes and businesses at an accelerating pace," said Tumilowicz. "Utilities have a chance to get ahead of this emerging trend and develop the programs, procedures, incentives, and systems so that what is deployed provides the most value to their customers and grid operations."

KEY EPRI TECHNICAL EXPERTS

Nick Tumilowicz

EPRI JOURNAL

Next-Generation Heat Pumps Are Making Customers Happy

Technology is Potentially Applicable to 90% of the U.S.

By Steve Kerekes

At 25 residential and commercial sites in 6 states across the continental United States, EPRI is testing advanced, electric heat pumps for replacing propane heat, natural gas systems, and older heat pumps. With respect to comfort, cost, and efficiency, results to date are promising.

This 'next-generation' system is potentially applicable to 90% of the U.S. population. The implications are significant: if electric heat pumps were to displace 90% of fossil fuel use for residential space heating, on-site fossil fuel consumption in the U.S. would be reduced by nearly three quads. For context, in 2020 the U.S. consumed a total of about 30 trillion cubic feet of natural gas, which is equivalent to approximately 31 quads of energy.

Heat pumps use electricity to move heat from one area to another. They can heat cold rooms or cool hot rooms and are far more efficient than heating systems that burn fossil fuels. Yet in colder climates, their use has been limited by lower heating capacity and efficiency. Below a certain outdoor temperature, the heat pump is supplanted by less efficient electric resistance heating or fossil fuel heating to provide additional warmth. As a result, most heat pumps are deployed in the Southern U.S.

For several years, EPRI has been working with manufacturers to develop a heat pump with a variable-speed compressor that operates more efficiently and can provide up to 50% more heating capacity at low outdoor temperatures than a similarly sized traditional system with a single-speed compressor. Variable-speed units run at low speeds for most of the day, then speed up during colder nighttime hours.

EPRI's field tests have determined that in a range of climates the variable-speed units provided warmth much more evenly and cost-effectively than the systems they replaced.

"The customers' reception has been very good," said EPRI Program Manager Ron Domitrovic. "They are benefiting from a significant reduction in energy consumption and report superior indoor comfort compared with their older systems. At all test sites, they have told us that the comfort and temperature throughout the house are more even than they've ever experienced before."

EPRI monitors the heat pumps' performance along with numerous variables that affect their operation, including outdoor air temperature and humidity, temperature of heat pump supply air, temperatures in various rooms at each site, and more.

One collaborator in the field tests is Tri-State Generation and Transmission, which supplies electricity to 43 distribution cooperatives and public power districts in Wyoming, Colorado, Nebraska, and New Mexico. Tri-State has deployed heat pumps at five houses in its members' service territories. The houses vary from one to three levels and from 1,160 to 3,356 square feet of heated space.

"Our primary insight is verifying that these heat pumps work in colder climates, and they do it economically and efficiently," said Myles Jensen, Tri-State's senior manager of member relations.

In a Nebraska farmhouse, the heat pump saved $211 in heating costs between December and April. The owner reported that the system is heating evenly and at lower outdoor temperatures more efficiently and economically than the propane furnace it replaced.

"The value of EPRI's expertise in collecting and analyzing the heat pump data in our field tests has been immeasurable," Jensen said. "It is essential to have rigorous data that we can use to demonstrate the effectiveness of variable-speed heat pumps to our member distributors and their customers."

At certain test sites, researchers also are investigating advanced heat pumps' support for demand response. Some manufacturers produce variable-speed heat pumps that can reduce compressor speed in response to utility signals during peak demand. In 2019, the Air-Conditioning, Heating and Refrigeration Institute established operating requirements for variable-capacity heat pumps with demand response capabilities, standardizing both system communication and heat pump response.

"With these variable-speed systems, even as you slow them down during peak demand on hot summer afternoons or cold winter mornings, they can provide moderate space conditioning very efficiently," Domitrovic said. "This benefits consumers and grid operators."

According to EPRI Senior Project Manager Don Shirey, the project's biggest challenge has been educating local HVAC contractors about installing, maintaining, and optimizing the new heat pumps.

"Many HVAC contractors only have experience with single-speed heat pumps and don't yet fully understand the capabilities of variable-speed systems," Shirey said. "Selecting the proper equipment size for variable-speed systems is different than sizing conventional systems. In addition, there are numerous thermostat settings that affect performance, and it's very important to select the settings appropriate for a particular climate."

Shirey works with HVAC contractors to assess their sizing calculations and select proper settings. Ultimately, he plans to develop guidance for contractors.

The project also revealed a need to educate homeowners about how variable-speed heat pumps operate.

"Homeowners are used to hearing their heating system cycle on and off rather than running all the time. When the variable-speed heat pump runs most of the time, they get nervous, thinking 'I must be using a lot of energy,'" Shirey said. "The reality is that the variable-speed units run at low speeds virtually the entire day. This mode of operation is much more efficient than a single-speed system running at full speed periodically."

KEY EPRI TECHNICAL EXPERTS

Ron Domitrovic, Don Shirey

EPRI JOURNAL

Photo of a Rose Pogonia Orchid on a TVA right-of-way courtesy of Theo Witsell

Power Line Rights-of-Way: A Haven for Disappearing Grassland Ecosystems?

By Michael Matz

In the U.S. Southeast, preliminary results of EPRI field studies with Southern Company and the Tennessee Valley Authority (TVA) indicate that well-managed power line rights-of-way (ROWs) can increase biodiversity and conserve fragile grassland ecosystems.

Throughout the United States, development and urbanization have nearly eliminated grassland ecosystems. In the Southeast, the roughly 120 million acres of grasslands believed to exist at the time of European settlement have declined by more than 90% as a result of habitat loss and fragmentation.* Many ecologists believe that it is important to conserve the grassland remnants because they contain a large portion of the region's biodiversity.

Many utilities use integrated vegetation management (IVM) on ROWs to remove tree sprouts and other woody vegetation that can damage power lines. (To learn more about IVM, see this fact sheet and these additional resources from the U.S. Environmental Protection Agency.) IVM often includes planting native vegetation, periodic mowing, and herbicide applications. If properly managed, ROWs can mimic natural grasslands and serve as 'surrogate' habitats for forbs, grasses, and other flowering grassland plants. This in turn can promote abundance and diversity of bees and other insect pollinators. In field tests with utilities, EPRI is examining how vegetation management strategies can suppress trees and invasive plants while supporting native plants and pollinators.

CENTRAL ALABAMA: EXPLORING THE RELATIONSHIP BETWEEN IVM AND BIODIVERSITY

Southern Company, its subsidiary Alabama Power, Auburn University, and EPRI are collaborating on a field study in central Alabama, with two main objectives:

- Quantify the biodiversity of flowering plants and insect pollinators on ROWs
- Evaluate the effects of commonly used IVM practices on this biodiversity

Between May and October 2018, researchers conducted baseline surveys of plants and insect pollinators on four ROWs and adjacent forests. Two key findings:

- Of the 41 flowering plant species observed, 40 were in the ROWs and 4 in the adjacent forests.
- Of the 71 bee species observed, 68 were in the ROWs and 29 in the adjacent forests.

“The greater number of plants and bees in the ROWs compared to the forest indicates that the ROWs are supporting biodiversity,” said Ashley Bennett, an EPRI entomologist leading the field research.

In June 2019, researchers applied three IVM treatments on different ROW plots:

- **T1**: A sprayer mounted on an all-terrain vehicle applied a large volume of a broad-spectrum herbicide (a chemical that controls a wide array of grasses and broadleaf plants) throughout the entire plot.
- **T2**: Researchers manually sprayed small volumes of the same broad-spectrum herbicide on tree sprouts and invasive species. The remainder of the plot was not sprayed.
- **T3**: Researchers manually sprayed small volumes of a grass-friendly herbicide (a chemical that controls a wide array of broadleaf plants but not grasses) on tree sprouts and invasive species. The remainder of the plot was not sprayed.

Between June and October 2019, researchers surveyed plants and pollinating insects monthly. As of August 2019, they found that forb abundance remained the same in plots treated with T2, declined by 71% in plots treated with T1, and declined by 45% in plots treated with T3. Post-treatment bee abundance was the same for T1, T2, and T3.

“The fact that we found significantly more forbs with T2—the selective spraying of the broad-spectrum herbicide—suggests that targeted application on tree sprouts and invasive species can protect non-targeted plants like forbs,” said Bennett. “It’s not clear why we did not see the same positive effect on forbs in T3—the treatment where we selectively sprayed with the grass-friendly herbicide. These results are from the first growing season after treatments were applied. Because it can take several years for plants and pollinators to respond to vegetation management, we plan to monitor the plots until 2022.”

“Through this multi-year research project, Southern Company hopes to inform ROW vegetation management practices while advancing pollinator conservation,” said Claire Ike, a Southern Company senior environmental specialist who is leading the research. “The research is one example of the commitment of Southern Company and our subsidiaries to natural resource conservation in the communities we are privileged to serve and also call home.”

“Alabama Power is encouraged with the initial findings from this project,” said John Morris, arborist supervisor at Alabama Power. “We share a common view that herbicides are an effective tool for IVM. Through this research, we hope to better understand herbicide products and application methods that not only achieve operational goals, but also increase and improve pollinator habitat.”

CUMBERLAND PLATEAU: PLANT AND POLLINATOR SURVEYS

Nearly all the grasslands and savannas that once dominated the Cumberland Plateau region—which spans eastern Kentucky, eastern Tennessee, and parts of northern Alabama and Georgia—have been lost to forest encroachment and development over the last 200 years. TVA’s power line ROW network is preserving remnants of this ecosystem.

“We have found many populations of rare plant species on TVA’s ROWs on the Cumberland Plateau and have come to understand these habitats as regionally important for plant conservation,” said Adam Dattilo, a botanist at TVA. “With the emergence of the global pollinator crisis, I began wondering if TVA’s standard vegetation management practices benefit pollinators in addition to helping plants.”

Similar to the T2 treatment in the Southern Company study, TVA’s vegetation management teams manually and selectively apply small amounts of herbicide to woody species that could damage power lines. TVA is collaborating with Southeastern Grasslands Initiative (based at Austin Peay State

University), the Mississippi Entomological Museum, and EPRI to examine the extent to which this approach can support conservation of grassland biodiversity.

Researchers designed a three-year study to compare plant and pollinator biodiversity in 15 ROW sites with that of 15 adjacent forest sites. In 2019, they surveyed plots (17 meters by 17 meters) on 5 ROW and 5 forest sites. Preliminary results:

ROW plots had between 118 and 131 plant species—or an average of 2.5 times the number of plant species as adjacent forest plots.

Four orchid species were found in ROW plots.

Pan traps in ROW plots caught an average of 16.1 times more bees than pan traps in forest plots.

Timed net sampling yielded an average of 13.8 times more bees in ROW plots than in forest plots.

"Similar to the data from our ROW research with Southern Company in central Alabama, these data show that TVA's ROWs have much greater biodiversity than the surrounding forest, suggesting that vegetation management practices are protecting native plants and pollinators," said Bennett. "In addition, many of the species we're finding are not weedy species. They're indicative of high-quality grassland remnants."

Over the next several years, researchers plan to survey plant and pollinator communities on 10 additional ROW plots and 10 adjacent forest plots.

"Ultimately, these results will help us better communicate the environmental benefits of the TVA ROW vegetation management program to the general public," said Dattilo. "Perhaps more importantly, from a conservation perspective, this project will illustrate the urgent need for grassland restoration on larger tracts of land outside of TVA's ROWs to conserve pollinator and plant biodiversity into the future."

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KEY EPRI TECHNICAL EXPERTS

Ashley Bennett

Photo of Frito-Lay production line courtesy of Frito-Lay

Production of Snacks, Uninterrupted

EPRI, CenterPoint Identify Modifications to Improve Power Quality at Frito-Lay Facility

By Michael Matz

Production of delicious snacks is running much more smoothly thanks to an EPRI power quality assessment at Frito-Lay's Rosenberg, Texas facility. In 2017, EPRI and utility CenterPoint Energy identified modifications in the facility and on the grid to enhance the plant's power quality and significantly reduce production shutdowns.

APPLYING DECADES OF POWER QUALITY EXPERIENCE

Since the 1980s, EPRI's Industrial Assessment team has conducted more than 300 power quality assessments in 11 industrial sectors worldwide. EPRI has power quality expertise both on the utility and facility side of the meter—a rare combination—and collaborates with utility and facility staff on assessments. EPRI's recommendations often yield hundreds of thousands of dollars in annual savings.

"Power quality assessments are like solving puzzles," said EPRI Principal Project Manager Mark Stephens. "We examine power quality data and equipment in a facility, find the weak links causing the shutdowns, and figure out the lowest cost solutions."

Stephens reports that the most common problems involve devices such as sensitive AC relays and automation equipment that are susceptible to voltage sags in the power supply. When the voltage dips below a certain threshold, equipment and processes may shut down—often at significant cost to industrial facilities. Solutions often include deploying new devices that can continue operating during—or "ride through"—deeper and longer voltage sags.

Through more than three decades of research, laboratory testing, and industrial assessments, EPRI has collected extensive power quality data, such as equipment performance during voltage sags. During assessments, EPRI's Power Quality Investigator software draws on this database to determine those devices most susceptible to interruptions along with potential solutions and their costs.

"What makes EPRI so skilled at these assessments is that our technical staff are applying decades of research," said Stephens. "Unlike others who do this work, EPRI doesn't come connected with any particular vendor or technology. We're not trying to sell equipment, so we can be objective in our recommendations. We present solutions as a menu of options with different costs and paybacks, and we never recommend solutions that we haven't tested thoroughly in our labs."

Need Help with Industrial Power Quality?

Contact PQServices@epri.com.

THE ASSESSMENT: PANELS, CONTROLS, AND EQUIPMENT

Frito-Lay's Rosenberg facility reached out to EPRI and CenterPoint to address voltage sags that caused production line shutdowns.

"Frito-Lay has a workforce of multi-trade technicians that perform equipment maintenance and troubleshooting," said Chris Allison, a senior principal engineer at Frito-Lay. "The type and severity of the power quality issues at the Rosenberg facility were outside of their expertise. Outages not only cause waste in product and labor but also create conditions that require a great deal of care to protect the safety of the people and equipment in the plant. We needed an engineering study that could identify the root causes and recommend solutions to eliminate the outages."

The EPRI team examined engineering drawings, facility power quality data, and shutdown logs and inspected production line equipment, electric panels, and wiring as well as support systems such as water chillers and compressed air. They identified programmable logic controllers, relays, and motor starters that are sensitive to voltage sags and recommended replacing them with inexpensive devices able to ride through sags. EPRI also found dead batteries in uninterruptible power supplies in equipment control panels, recommending battery-less protective devices.

"During assessments, we commonly find dead batteries in uninterruptible power supplies," said Stephens. "These devices are often used in places that aren't regularly maintained, and there are no alerts when the batteries die. We often recommend other devices that provide the same function—uninterrupted electric service through voltage sags—but that don't need batteries."

Stephens says that fixes at individual electric panels, machines, and control devices (where power is low voltage) are much less expensive than fixes at the level of the entire facility (where power is high voltage).

"Fixing machines and controls can cost hundreds or thousands of dollars while deploying technologies intended to protect the whole facility can cost millions of dollars," he said.

RECONFIGURING THE DISTRIBUTION GRID

EPRI estimated that its recommended modifications in the facility would address about two-thirds of the interruptions and that the remainder would require changes on the utility side of the meter.

As a part of a one-day "drive down" of the distribution grid supplying the facility, EPRI and CenterPoint staff examined nearby feeders and substations to assess how grid faults may contribute to voltage sags and power interruptions. EPRI also modeled the impacts of faults on the facility. CenterPoint and EPRI agreed that the best solution was to reconfigure several feeders in the area to reduce the facility's exposure to faults.

"Faults on a distribution feeder can lead to voltage sags in facilities served by the feeder," said Stephens. "They can also cause interruptions at sites served by adjacent feeders. The location of the Frito-Lay facility with respect to various feeders in the area exposed it to an unusually high number of faults. Reconfiguring the feeders to reduce fault exposure is much less expensive than deploying equipment that enables the facility to ride through the grid interruptions."

"EPRI plays a valuable role in enhancing the utility-customer relationship. Through its power quality assessment at a large customer's facility, EPRI's affirmation of the utility work already completed or underway—as well as the specific identification of issues within the facility that the customer could address—resulted in several efficiencies and improvements," said Scott Cryer, power quality manager at CenterPoint Energy.

Since the Rosenberg facility implemented EPRI's recommendations and CenterPoint reconfigured the nearby grid, Frito-Lay estimates annual facility savings of about $100,000.

"The great thing about EPRI is they have a vast amount of experience in eliminating power quality issues on both the utility and the customer side," said Frito-Lay's Allison. "The trust in EPRI's expertise helped all parties to jointly resolve these issues. The end result was an elimination of outages as a result of sags and other power quality issues. Even weather-related outages due to thunderstorms were eliminated by hardening the Frito-Lay systems and reconfiguring the utility distribution to the plant."

Prior to the Rosenberg assessment, EPRI conducted power quality assessments at Frito-Lay facilities in Ohio, Virginia, Arkansas, California, Kansas, and Utah. An assessment is planned for a Frito-Lay facility in Orlando, Florida.

KEY EPRI TECHNICAL EXPERTS

Mark Stephens

Photo of Pickering Nuclear Generating Station courtesy of Ontario Power Generation

Pickering Goes Wireless

EPRI and Ontario Power Generation Collaborate on Deployment of Wireless Sensors to Modernize Nuclear Fleet

By Chris Warren

Drawing on extensive EPRI research, Ontario Power Generation (OPG) deployed and tested its first wireless sensor network as part of a pilot project at Pickering Nuclear Generating Station. The effort was an important step in OPG's plant modernization initiative, which aims to continuously monitor plant conditions to drive analytics and predictive maintenance across the utility's 6.6-gigawatt nuclear fleet. OPG plans to dramatically expand its sensor network, expecting it to save 36,000 man-hours.

EPRI's survey of commercially available wireless sensors informed OPG's consideration of various options' features and capabilities. OPG then used EPRI's engineering guide to support installation of 12 wireless sensors at 6 locations in Pickering's unit 5 reactor. One set of sensors monitored vibration, ambient temperature, and humidity on a condenser cooling water pump and motor. Another set of sensors on standby generator batteries monitored voltage, humidity inside the battery cabinets, and ambient temperature. Other sensors were installed on pumps and motors.

After four months of testing, the main takeaway was that the sensors reliably collected and transmitted information about equipment operations. "We demonstrated that the sensors were not causing any malfunction on the critical equipment in Pickering," said Abuzafar Ali, Pickering's section manager for nuclear engineering.

OPG has established a Monitoring and Diagnostic (M&D) Center at Pickering, where analysts use advanced pattern recognition to analyze sensor data and identify when equipment is operating as expected or abnormally. The company aims to deploy enough wireless sensors to implement continuous monitoring of equipment at its Pickering and Darlington nuclear power plants, driving insights on maintenance and operations at M&D Centers. Wireless sensors can transmit data to a central location at a fraction of the cost of wired sensors.

"We have a lot of wired sensors at Pickering now," said Abuzafar. "However, because the M&D Center wants to continuously monitor all plant operations, we need more coverage in the plant and more data. That drove the need for wireless sensors.”

OPG plans to install several thousand wireless sensors at the Pickering and Darlington plants over the next several years. When that is complete, Abuzafar believes that OPG will be able to transition from scheduled equipment inspection to predictive maintenance. The new capabilities will equip plant staff to prioritize equipment repairs and replacements. OPG estimates that the addition of these sensors will save about 36,000 hours in operations, maintenance, and engineering work.

KEY EPRI TECHNICAL EXPERTS

Rob Austin, Steve Lopez

EPRI JOURNAL

Photo of Kogan Creek Power Station courtesy of CS Energy

Taking Ultrasonic Inspection to the Next Level in Australia

By Michael Matz

With technical assistance from EPRI, Australian power provider CS Energy successfully applied a cutting edge ultrasonic inspection technique, enabling the replacement of a major component at one of its power plants, shortening the outage schedule, and potentially avoiding millions of dollars in future maintenance costs.

A BETTER WAY TO INSPECT BOILERS

Inside power plant boilers are tall walls comprised of water-filled tubes that are welded together. The boiler's furnace heats the tubes, and the water inside turns to steam. Historically, many power plants around the world have used radiography to examine boiler tube welds and assess repair needs. This involves shutting down the boiler, directing X-rays at a weld or other boiler materials, and capturing the X-rays on radiographic film after they penetrate the materials.

Radiography has downsides. To minimize worker exposure to radiation, other maintenance work in the area must stop during the inspection, increasing costs. As a result, radiography is typically performed only during short periods late at night, when other technicians are not on site. The film must be processed and interpreted in a lab to identify welds and other components in need of repair. These activities can take days or even weeks.

With recent technology developments, phased array ultrasonic inspection has emerged as a potentially safer, faster option for weld inspection in boilers. A hand-held phased array device simultaneously directs multiple ultrasonic beams into a weld and combines the reflected beams to create an image of any flaws or defects. Unlike radiography, ultrasonic beams do not pose human health risks, so other maintenance work can proceed during the inspections. The results are available immediately, enabling technicians to analyze defects and immediately repair welds.

A DEEP DIVE INTO ULTRASONIC INSPECTION AT KOGAN CREEK

CS Energy's 750-megawatt, coal-fired Kogan Creek Power Station is located near Chinchilla, a small Australian town about 200 miles northwest of Brisbane. Kogan Creek maintenance staff discovered significant corrosion in the boiler's reheater and planned to replace the damaged section during the next major plant maintenance outage. The reheater replacement would require inspecting about 5,000 new boiler tube welds and repairing ones found to be defective. Historically, Kogan Creek has used radiography for testing thin-walled reheater tube welds, but the staff were concerned about potentially costly work stoppages that would be required during radiography inspections. They knew that EPRI had previously helped another power plant 100 miles away (Millmerran Power Station) implement phased array inspections and requested similar technical assistance. EPRI has a long-running program to help power plants improve their inspection techniques.

“Reheater replacements require accuracy and precision,” said Jay Richardson, an EPRI expert on inspection of power plant components. “The tube walls are just a few millimeters in thickness. Scratches and other defects measuring less than one millimeter could lead to boiler failures, which can result in several million dollars in replacement costs. Phased array ultrasonic technology can provide the accuracy needed to eliminate defects. The ultrasonic technician and the welder can do their work simultaneously. As the technician inspects new welds and generates ultrasonic images, the welder can refine welding processes and materials based on the images. If a problem is identified with a weld, it is replaced.”

CS Energy’s engineering manager wanted EPRI to review the phased array protocol proposed by the plant’s nondestructive evaluation (NDE) vendor (Intertek) because the tube dimensions were outside the range where phased array inspections had been applied in the past.

EPRI’s Richardson reviewed the vendor’s proposed protocol and recommended refinements based on the latest advances in ultrasonic technology. He fabricated mockups of the plant’s boiler tubes and brought them to the vendor’s testing facility in Brisbane, where the team demonstrated the refined technique. Using computer simulation, Richardson analyzed the results and recommended further refinements (such as different equipment settings) to improve the accuracy of defect detection. The vendor successfully implemented the technique at the plant during the reheater replacement, with assistance from Richardson in interpreting ultrasonic images. Plant technicians used radiography and destructive methods to examine numerous welds, confirming the presence of defects identified by the phased array inspection.

“The replacement of the Kogan Creek horizontal reheater was a large logistical exercise involving removal and replacement of 588 reheater elements,” said Ian Rawlings, who manages power plant boilers for CS Energy. “While phased array inspection has been used on previous tube replacements, it hadn’t been used for thin-walled reheater tubes. Our NDE contractor Intertek developed a procedure to detect and size defects in the welds. With input from EPRI, the procedure was revised to enhance its accuracy. Additionally, EPRI supplied sample welds with and without defects, and these samples were used to train and verify the competency of the NDE technicians. Since returning to service in 2019, the plant has not experienced any leaks in the new reheater section.”

NEED TO SHARPEN YOUR INSPECTION SKILLS? EPRI CAN HELP

In response to a growing share of renewable energy in the electric power system, thermal power plants around the world increasingly cycle up and down or shut down temporarily—modes known as flexible operations. Because many plants were not designed to operate under these conditions, they can lead to damage of critical components. More than ever, it is essential for power plants to have expertise in nondestructive evaluation (NDE)—inspection with technologies that can probe and penetrate metals and reveal defects without damaging plant components. NDE can help plant operators identify emerging problems with components and plan for repairs and replacements.

Since 2012, EPRI has run a program to assess the proficiency of NDE technicians in applying advanced inspection techniques at power plants, with an objective to demonstrate that NDE procedures, equipment, and personnel can achieve a high level of accuracy in detecting and characterizing damage. As part of the program, EPRI technical experts help plant operators and their NDE vendors refine inspection protocols based on the latest technologies, expand application of advanced techniques, interpret data, and better understand damage mechanisms. EPRI’s NDE laboratory in Charlotte, North Carolina has a large inventory of service-damaged plant components that are used for analyzing damage mechanisms and fine-tuning NDE techniques. Nine power companies around the world currently participate in the program, which has completed more than 470 proficiency assessments to date.

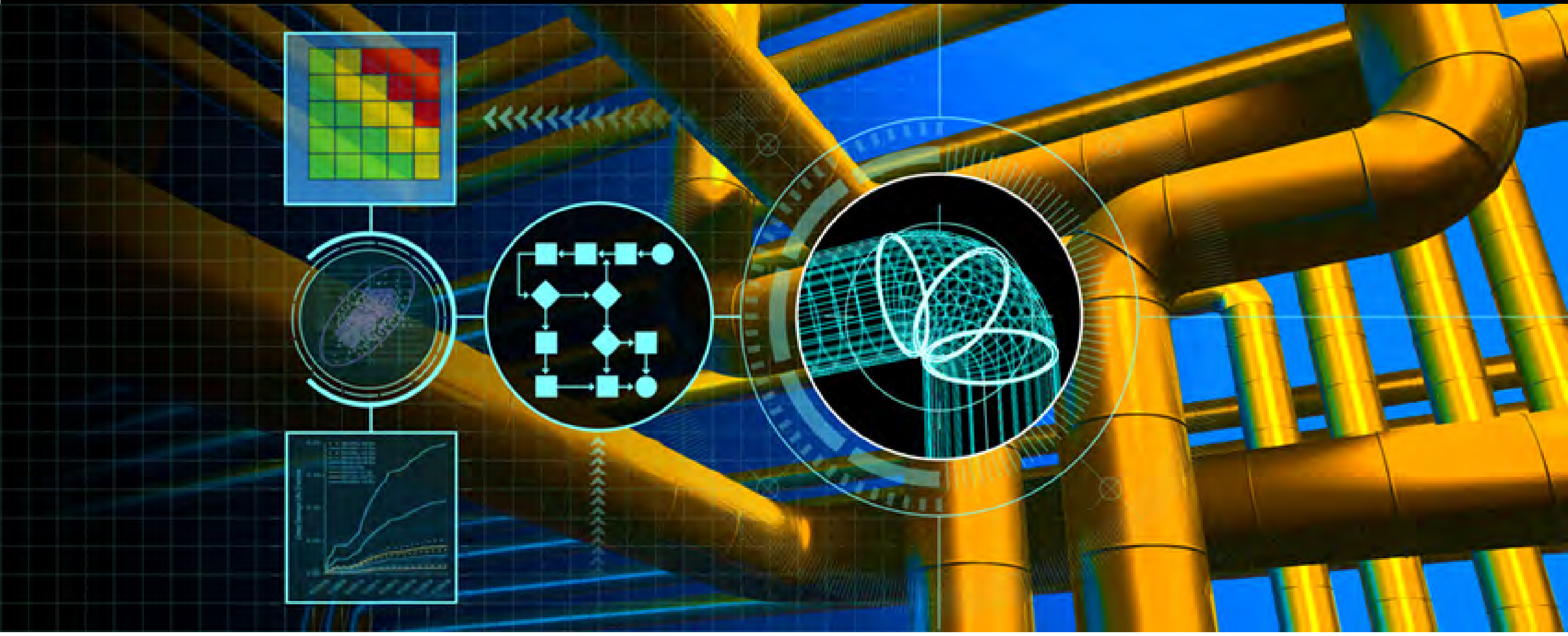
“NDE inspections and analysis are critical to the safe and reliable operation of power plants,” said Mike Ruszkowski, who leads research in EPRI’s NDE group. “If improperly executed, they could lead to substantial financial loss and potential safety concerns for both equipment and personnel. An inspection that misses signs of potential component failure could lead to significant unexpected cost in repairs or replacements. On the other hand, an incorrect prognosis of a failure could lead to unnecessary maintenance costs and loss of production due to a plant outage.”

Through its ongoing communications with power plant operators around the world, EPRI’s NDE program is well-positioned to identify emerging problems related to plant cycling and other flexible operations. “Our NDE research team supports power companies globally,” said Ruszkowski. “This allows us to work with multiple utilities on a wide range of issues and identify common problems that require further research.”

KEY EPRI TECHNICAL EXPERTS

Jay Richardson

EPRI JOURNAL



What is the Best Action to Address Damage in a Power Plant

EPRI Is Developing Technically Rigorous, Customized Methods to Answer this Question

By Michael Matz

Operators of fossil power plants around the world face a growing dilemma: they are finding more plant damage. Two factors are driving this trend. First, aging plants increasingly operating in flexible modes for which they were not designed have the potential for cracks and other damage to develop in components at an accelerating rate. Second, operators are pursuing more comprehensive strategies to manage the health of systems and components, which includes more targeted, thorough inspections. As more damage is discovered, it may eventually be impractical to repair or replace every affected component.

"Historically, if plant operators found a crack in a component, they repaired or replaced it," said John Siefert, who manages the [Materials and Repair Program] in EPRI's Generation sector. "If we assume in today's challenging environment that operators cannot afford to repair or replace everything, then for each damaged component, they will need to answer: Is it fit to remain in operation as is without sacrificing plant safety or reliability? Or, are repairs absolutely necessary before it can return to service? Or, is it beyond the point of repair and requires replacement?"

Recognized codes or standards used today by power generation engineers to answer these questions are inadequate because the information they provide is general in nature. Methods typically used to assess a power plant component's fitness for service do not consider the components, materials, and damage mechanisms unique to the power generation industry. Indeed, common fitness-for-service standards are used by several industries. As a result, the technicians and engineers who apply the methods need to make assumptions, which could excessively increase the uncertainty of fitness-for-service assessments.

Much of the available mechanical data used in fitness-for-service assessments comes from databases populated with information about new materials. This can result in additional uncertainty because an assessment may need to consider a power plant component that has been in service for hundreds of thousands of hours.

"There hasn't been a systematic study on power industry fitness-for-service methods in more than 20 years," said Siefert. "Plant operators need well-engineered methods to conduct targeted studies on component and damage scenarios specific to the power industry. For example, a useful method might tell you that if you have a certain pipe weld made of material X exhibiting damage mechanism Y, you need to collect Z data to execute a well-informed calculation to assess the weld's integrity."

A COMPREHENSIVE FITNESS-FOR-SERVICE FRAMEWORK

EPRI has launched a four-year project to develop a technically rigorous fitness-for-service framework to assess the plant components at greatest risk of in-service damage as well as those that require the most technically challenging repairs and replacements. The objectives are to provide a well-engineered basis for safe, cost-effective plant operations and to inform critical decisions regarding inspection, monitoring, and maintenance. Plant owners, engineering organizations, nondestructive evaluation companies, and other specialists and service providers involved in fitness-for-service assessments are invited to participate in this collaborative research.

As a first step, EPRI and the project participants are prioritizing an extensive list of scenarios defined by specific components, damage mechanisms, and materials. "Based on the most common questions I hear from plant operators, I expect that the priorities will include high-temperature headers, high-energy piping systems, steam and gas turbine casings, and large-bore valve bodies," said Siefert. "These components are very expensive to replace, and many plants already take a 'repair and run' approach with them."

Methods to assess components will be designed to keep analyses simple when possible. "You don't want the process to be more complicated than it needs to be," said Siefert. "Depending on the complexity of the problem, the fitness-for-service framework could lead the user to make a simple calculation or conduct a more detailed analysis. If the component is deemed unsafe using the simple route, then the framework might direct the user to a more complex set of data and calculations to confirm or revise that conclusion. EPRI is investigating how modern computer software can facilitate complex analyses."

To provide flexibility, the fitness-for-service methods will offer users a set of options on how to address damage. For example, as an alternative to a costly repair for a component, a method may lead a user to conclude that a less expensive welding technique is sufficient to achieve fitness for service—or that repairs can be avoided altogether if the plant's operational mode is adjusted.

The best path forward will be different for each scenario. "An evaluation of one component may find that a crack is likely to lead to an inconsequential leak—and is therefore potentially fit to operate," said Siefert. "Meanwhile, an assessment of another component may determine that a crack may result in a catastrophic rupture and a costly plant outage in an unacceptable timeframe. Replacement may be the best option in this case."

Installing sensors on components to track degradation is an important part of effective fitness-for-service evaluations. In order to capture useful component data, such as temperature or strain, the project will provide specific guidance on where to place sensors, when to collect the data, and how to use the data to assess component integrity. For instance, welds have multiple constituents, each with unique properties—information that can be critical to informing where and how to monitor a component.

Project participants are encouraged to provide EPRI with service-damaged components and case studies on component damage, its causes, and its progression over time. The components and case studies can be used to validate the fitness-for-service methods developed in the project or to develop relevant material property data. Evaluating components made by many different manufacturers makes EPRI uniquely qualified to provide industry-wide fitness-for-service guidance.

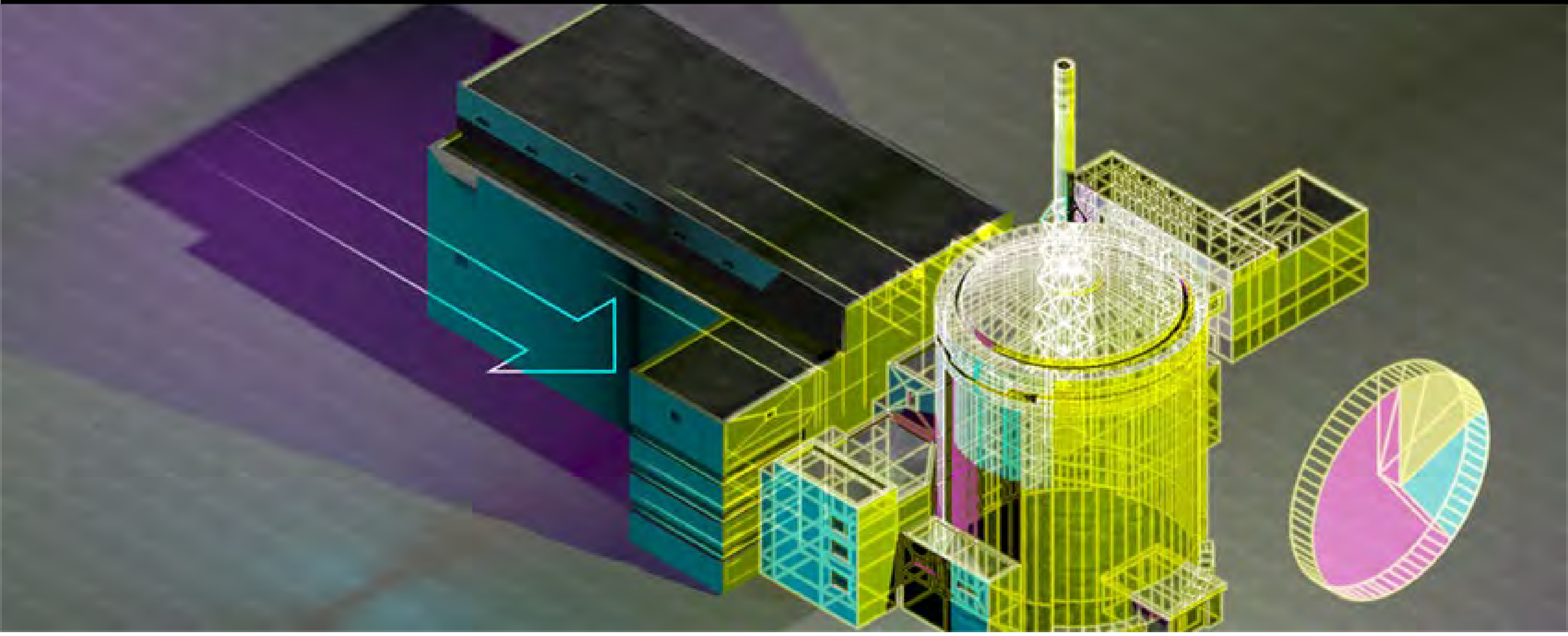
"EPRI invites the participants to share their experiences and perspectives on the challenges of applying fitness-for-service methods," said Siefert.

To reduce the uncertainty of the inputs for fitness-for-service assessments, EPRI plans to develop specifications and best practice guidelines as well as recommend additional training. EPRI and the participants will regularly review these and other outcomes of the project.

To facilitate application of the methods by plant operators and fitness-for-service providers, EPRI plans to transfer key findings to the relevant code and standard organizations, where they will be subjected to peer review and potentially codified. EPRI technical staff have already discussed the project with the National Board Inspection Code (NBIC) and plans to involve this organization in the project's review process.

KEY EPRI TECHNICAL EXPERTS

John Siefert and Jonathan Parker



What's the Best Way to Modernize a Nuclear Plant? New EPRI Tools Can Help Answer That Question

By Michael Matz

With increasing renewable energy deployment, low-cost natural gas, and low electric load growth, nuclear power plants across the world face significant pressure to reduce costs. Utilities and policy makers view modernizing plants with updated processes and digital technologies as a promising path to make nuclear energy more economically competitive with other generation technologies. If successful, modernization can enable nuclear plants to continue providing carbon-free energy and contribute to cost-effective, reliable decarbonization efforts around the world.

Now, plant operators need to figure out how to modernize each facility in a way that reflects its unique features and circumstances. Should a plant embark on a large-scale program with improvements throughout the site that fundamentally alter the facility's operations and maintenance? Or should a plant pursue a more limited program with focused improvements that address the most significant inefficiencies and the systems in most urgent need of repair? Or focus on a minimal program that upgrades only components and systems at the end of their lifetimes?

EPRI's Plant Modernization Toolbox helps plants answer these questions. The tools are comprehensive and can guide users through developing a modernization strategy, identifying a potential suite of improvements, conducting business case studies on proposed improvements, making decisions based on the business case results, deploying improvements, and tracking the benefits.

"Stakeholders across the nuclear industry agree that plants may not survive unless they modernize," said EPRI Senior Program Manager Rob Austin. "These tools enable plants to develop the modernization strategy that is right for them—and that can make them competitive. Our analyses have demonstrated that a cost savings of 25% can justify significant investment for many sites."

There are dozens of potential modernization improvements, such as digital controls, wireless connectivity, continuous equipment monitoring, and data analytics that provide actionable insights on operations and maintenance. These plant modifications can yield cost savings in numerous ways, including more efficient use of labor, fewer scheduled maintenance tasks, fewer unplanned outages, avoided component failures, and improved plant performance and personnel safety.

A good starting point for plant operators is EPRI's guidance for developing a modernization strategy and establishing and executing a modernization program. It guides users through the entire modernization process—from drafting a charter to implementing improvements to tracking the benefits.

When plant operators are ready to consider improvements for their facilities, they can browse through EPRI's series of Modernization Technology Assessments (MTAs). Each MTA is 3-4 pages long and provides a short description of a specific improvement, its potential investment costs, and the potential savings it may deliver over time. The costs and savings are ballpark figures; actual figures will vary based on each plant's unique attributes and circumstances. For plant operators who want to learn more, MTAs include contact information for EPRI experts who can provide information about the relevant vendors and manufacturers as well as about the plants that have deployed the technology.

To date, EPRI has developed 42 MTAs. On the Plant Modernization Toolbox website, users can review the MTAs and other resources to facilitate decision making and execution of modernization initiatives.

"We want to develop an extensive library of Modernization Technology Assessments that plant staff can browse through as they consider how to develop their modernization programs," said EPRI Principal Technical Leader Chris Kerr. "We encourage manufacturers, vendors, utilities, national laboratories, and other nuclear industry stakeholders to use our template to develop MTAs for their own modernization technologies and processes—and we will add those to our searchable library on our website. Our goal is to have more than 75 MTAs by the end of 2021."

As a next step in developing a modernization initiative, plant operators can use EPRI's business case analysis model (BCAM) to quantify the financial costs and benefits of improvements at a plant. Users input various data into the Excel-based tool, such as historical maintenance costs using existing technologies, data from manufacturers on installation and operational costs of new technologies, and data from other plants on savings from improved plant performance or reduced manual inspections. Based on the inputs, the tool provides financial metrics such as the net present value of the savings and the return on investment over the plant's life. The results of business case analyses can help plant leadership make informed decisions on whether to proceed with improvements.

"Some modernization improvements do not offer direct savings but can help maximize savings from other improvements," said Kerr. "The tool enables users to evaluate the total benefits achieved through such synergies. Users can experiment with evaluating different combinations of improvements to maximize benefits."

Collaborating with nuclear utilities, EPRI has applied the model to a series of business case evaluations, publishing the results throughout 2020, with more to come in 2021. Each evaluation provides instructions on how other utilities can repeat the analysis for their sites.

Applications of EPRI's business case analysis model span a range of modernization improvements and expected savings. A few examples:

- Idaho National Laboratory found that a large-scale digital upgrade at a nuclear plant has a net present value of $50-70 million (INL/EXT-20-59371).
- An EPRI analysis revealed substantial operations and maintenance savings from the use of electronic work packages.
- EPRI found that the application of hydrophobic coatings to water pumps could yield a net present value of up to $1 million in maintenance-related cost savings (such as reduced cleaning of submerged equipment).

"Through the business case evaluations, we are learning about the attributes that modernization projects need to have for a strong business case," said Austin. "One emerging insight is that while it's important to be targeted and cautious, 'going bigger' with modernization is generally the best path to a solid return on investment."

"The amount of collaboration on the Modernization Technology Assessments and business cases has been phenomenal," said Kerr. "So far, 11 utilities have supported the development of MTAs, and 13 have supported business cases. Most plants face similar economic pressures to modernize and have recognized the importance of sharing their experiences, lessons, and cost and savings data associated with modernization improvements."

In 2021, EPRI is piloting the modernization strategy development process with two utilities. The results will be ready by the end of 2021.

KEY EPRI TECHNICAL EXPERTS

Rob Austin, Chris Kerr

EPRI JOURNAL

How to Improve Solar Performance? Benchmark and Share Best Practices

Growing Area of Collaboration Informs Operations, Maintenance, and Business Decisions at Large-Scale Solar Plants

By Lucinda Trew

At the end of 2019, Wood Mackenzie reported a cumulative solar photovoltaic (PV) capacity in the United States of more than 75 gigawatts*—about 75 times the installed capacity in 2010. With an expected operating life of 20-plus years, most of today's plants haven't reached the halfway mark. Given this relatively limited operational experience, more knowledge is needed about plant performance across fleets and over time.

To address this, EPRI is leading an industrywide benchmarking effort through which PV owners and operators can share data and insights about performance, operations, maintenance, vegetation management, technology trends, and other topics.

"Many companies are adding new PV plants to their generation fleets and in some cases are venturing into PV for the first time," said EPRI Principal Project Manager Michael Bolen. "EPRI's initiative enables them to benchmark plant performance based on industry data and determine what can be done to increase plant production and reliability."

While EPRI has been evaluating PV performance for a decade, only recently have enough commercially operating large-scale PV plants collected and shared data for substantive benchmarking. Through this broad benchmarking, participating plant owners provide EPRI with on-site meteorological and production data via secure communications. For each plant, EPRI checks the data for quality, uses them to calculate various metrics for actual and expected performance such as capacity factor and performance ratio, and compares the results with other participating plants. Additional analytical techniques are being developed to quantify and benchmark PV plants' performance loss and degradation rate over time. More than ten fleet owners currently participate, and the aim is to increase that number significantly.

EPRI has launched the Solar Owners League, which will manage these benchmarking efforts, provide a forum for sharing technical knowledge, and develop and apply analytical tools for benchmarking performance and reliability. EPRI plans to launch a benchmarking website that enables users to analyze data in various ways—such as comparing a plant's performance with others in a specific region or comparing the performance of fixed-tilt plants with single-axis tracking plants. While the website will offer some publicly available information, access to the website's benchmarking component will be limited to members of the league.

Duke Energy Renewables (Duke Energy's project development arm) owns and operates more than 850 megawatts of PV at more than 50 solar plants across the country and recognizes the value of EPRI's benchmarking initiative.

"Because solar is still relatively new and uncharted, it's difficult to obtain reliable benchmarking," said Josh Rogers, who directs commercial operations for Duke Energy Renewables, the utility's project development arm.

Rogers said that EPRI's initiative has provided Duke Energy Renewables with a better understanding of issues such as degradation rates. Insights gained through benchmarking have also helped Duke Energy Renewables prioritize maintenance tasks. For example, if a minor problem does not significantly affect energy production, deferring repairs until the next maintenance cycle may be more cost-effective than immediately dispatching a technician.

Effective vegetation management at PV plants can prevent fire hazards, enable maintenance technicians to access equipment, and help owners comply with jurisdictional siting requirements. Rogers reports that the opportunity to exchange experience with various vegetation management strategies in various regions has informed Duke Energy Renewables' management approach.

In addition to improving plant performance, benchmarking can inform business decisions. "When plant owners and operators have data-driven insights into long-term plant performance, they can make better decisions throughout the lifetime of their plants," said Bolen. "For example, benchmarking can inform decisions about plant designs and equipment best suited for a particular region as well as decisions on when to re-power, re-configure, or decommission plants."

During monthly Solar Owners League webcasts, leaders in plant management, operations, and maintenance share knowledge and discuss collaborative research opportunities. The first webcast highlighted EPRI's public release of the report Large-Scale Solar Photovoltaic Plant Performance and Degradation Benchmarking, which found that large-scale PV plants seem to lose nameplate power at a rate of 1% per year—greater than the 0.5% per year that is often assumed. More research is needed to identify and quantify the root cause of the loss and determine if the lost power is recoverable.

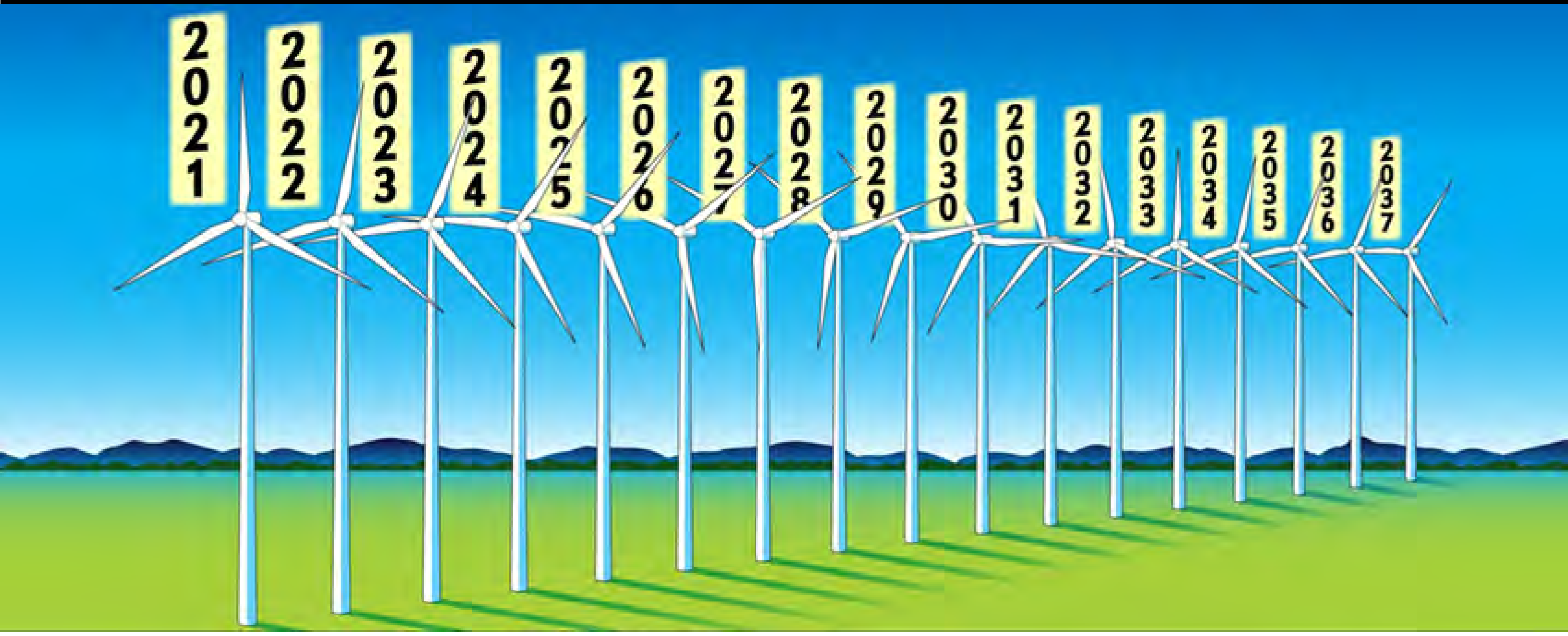
"EPRI's benchmarking efforts serve the greater good of our industry," said Rogers. "They drive a productive conversation among peers, which in turn informs future business decisions and manufacturing and equipment advances."

*Wood Mackenzie Data Hub, U.S. PV Market Forecasts

KEY EPRI TECHNICAL EXPERTS

Michael Bolen

EPRI JOURNAL



How to Extend the Life of a Wind Power Plant?

EPRI Study Reveals Ways to Improve Turbine Reliability and Accuracy of Performance Projections

By Michael Matz

Global wind generation capacity has increased by six times over the last decade. It is projected to triple over the next decade and increase six-fold by 2050. Along with this growth in capacity, advances in wind turbine controls are enabling wind plant owners and operators to use manufacturers' software upgrades to boost turbine power ratings. Such practices are common in an industry dominated by independent power producers selling energy through power purchase agreements that aim to maximize energy. While this practice (also known as uprating) can increase power production by as much as 5% short term, EPRI researchers have found that it can adversely impact long-term turbine reliability and economics.

"Increasing power rating means more production and revenue initially, but it puts more stress on a turbine's components and may reduce its lifetime," said Brandon Fitchett, who manages wind generation research at EPRI. "The amount of component fatigue depends on the magnitude of the rating change as well as site wind conditions."

Another common practice among developers, owners, and operators is to assume a plant lifetime of 25 years in cost projections without accounting for the site's wind conditions. These generic assumptions along with the uprating practices can increase the risk that plants do not meet long-term performance expectations.

The EPRI team used a state-of-the-art wind industry aeroelastic model to simulate power rating changes and various site wind conditions, calculating loads on a turbine's major components, such as the gearbox. This is the same type of model that site developers and owners use to verify and certify turbine designs and projected lifetimes. A second model examined how uprating and site wind conditions impact operations and maintenance (O&M) costs.

The main takeaway: Both power rating and wind conditions significantly impact turbine lifetime and O&M costs. For instance, increasing power rating by 7% could reduce gearbox lifetime by 10 years. Sites with high levels of turbulence could have half the gearbox lifetime relative to sites with low turbulence. A gearbox failure can cause an extended outage of a wind turbine, require a tall crane to replace the gearbox, and cost a few hundred thousand dollars or more in repairs and lost generation revenue.

"Slight decreases in wind turbine power rating can significantly reduce major component fatigue and significantly increase turbine life," said Fitchett. "If you expect your gearboxes are going to fail early, you may want to consider adjusting your power rating to extend the life of your turbines and reduce O&M costs."

Plant owners can use the study's results to create more realistic O&M budgets each year and set more realistic performance expectations over a turbine's life. Along with other EPRI research on component monitoring and reliability, the insights in this study can inform developers in selecting windfarm sites and component suppliers and in projecting component lifetimes.

"Most developers assume a 25-year lifetime when modeling the long-term economics of proposed wind power sites," said Fitchett. "This research indicates that they need to adjust that number based on rating and site conditions."

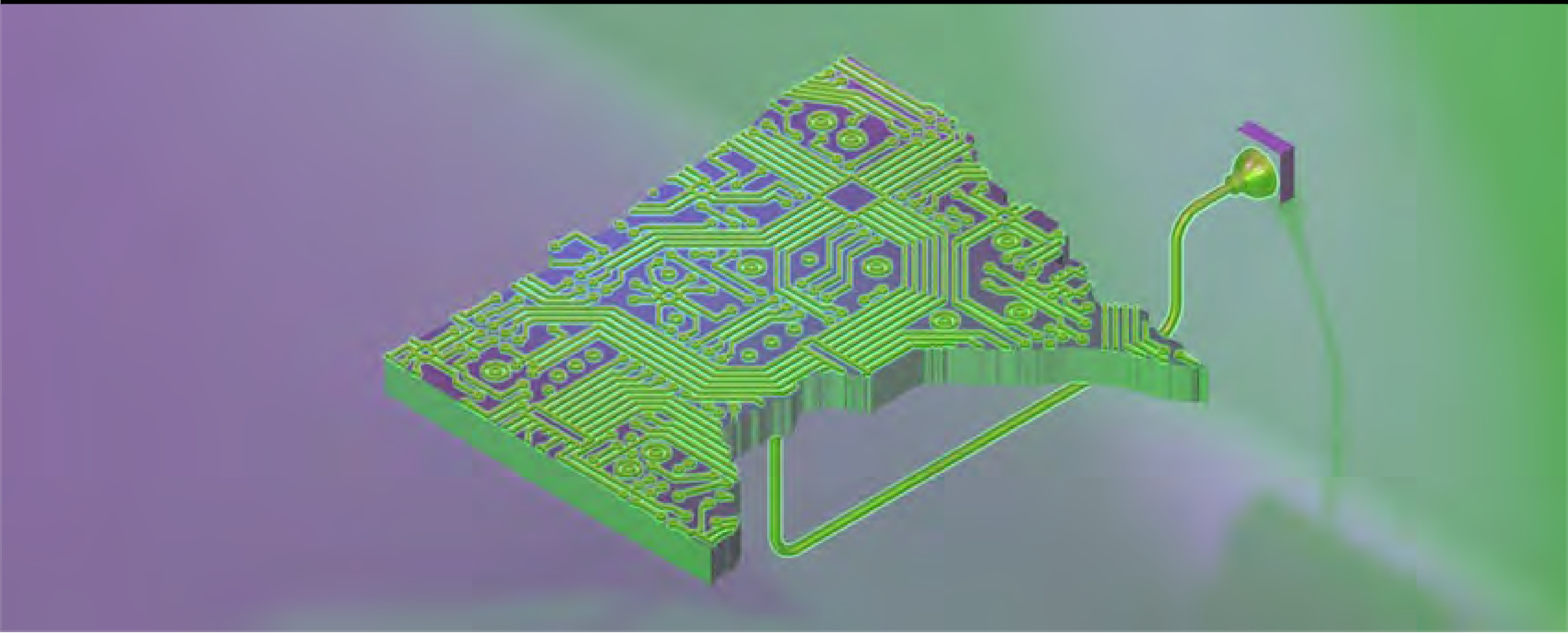
According to Fitchett, as wind generation grows and coal generation declines over the next decade, the operational strategies of wind plant owners are likely to shift from maximizing generation to providing reliable, flexible output and ancillary services. Indeed, keeping some wind farm power output in reserve could support a more reliable future power grid as well as a more reliable, longer-lasting wind farm.

"In 5 to 10 years, wind farms will likely need to be more flexible and dispatchable, with grid operators making broader use of curtailing wind power to balance the grid," said Fitchett. "When turbines are not running at maximum potential power, they're actually providing operators with a valuable grid service—grid-connected reserve power ready for immediate delivery."

KEY EPRI TECHNICAL EXPERTS

Brandon Fitchett

EPRI JOURNAL



How Can Minnesota's Electric Sector Be Decarbonized?

EPRI Delves into the Tradeoffs of Various Pathways

By Michael Matz

Across the electric power industry, many utilities are pursuing aggressive decarbonization goals. Concurrently, states are enacting policies to decarbonize their economies, prompting the question: how can these policies reinforce and augment utility initiatives? Prior EPRI research has shown that different policies with the same carbon reduction goals can have dramatically different consequences for a state's energy system. For instance, while some policies may increase revenues for out-of-state power providers, other policies may boost financial benefits for in-state companies.

These were among the issues that Great River Energy—an electric power cooperative that serves 28 distribution cooperatives and 700,000 customers in Minnesota—was examining in early 2019 as policy makers and power industry stakeholders were discussing the possibility of making the state's renewable energy standard more stringent. Enacted in 2007, the state's original renewable energy standard requires Xcel Energy, the state's largest utility, to generate 31.5% of its electricity from solar, wind, and other specified renewable energy sources by 2020. (Today, Xcel has a goal to reduce carbon emission 80% by 2030 and 100% by 2050.) The state's other power providers, including Great River Energy, have a 25% by 2025 requirement. The state has an economy-wide greenhouse gas emissions reduction goal of 80% by 2050.

In January 2019, Great River Energy asked EPRI for help in gaining a better understanding of how various decarbonization policies might change Minnesota's energy system.

"EPRI is an industry leader and brings an immense wealth of resources as well as expertise to the topic," said Zac Ruzycki who manages power supply planning for Great River Energy. "This project was formative in helping us to better understand what types of financial trade-offs would present themselves under multiple different potential policies aimed at reducing carbon emissions."

EPRI used its U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model to compare the economic outcomes and costs of two different policies intended to achieve the same decarbonization targets:

- Renewable energy standard: A Minnesota electric sector requirement for 60% wind, solar, hydropower, and other renewable energy resources by 2030 and 95% by 2050. EPRI showed that these targets could reduce carbon dioxide (CO_2) emissions of Minnesota's electric sector by 85–90% in 2030 and 90–95% in 2050 relative to 2005 levels.
- Technology-neutral CO_2 standard: A Minnesota electric sector requirement to achieve the same CO_2 reductions while allowing all energy resources, including nuclear power and fossil generation with carbon capture and storage.

The modeling analysis revealed that the technology-neutral policy could save Minnesota $2.7 billion in electric sector costs between 2015 and 2050. The higher costs of the renewable energy standard were largely due to the significantly greater purchases of wind power and associated renewable energy credits from the Dakotas and Wisconsin. Relative to the renewable energy standard, the technology-neutral CO_2 policy would support approximately the same amount of new in-state wind generation and lead to more overall in-state generation investment as well as 30% greater in-state electric sector revenues.

"We found that a technology-neutral approach takes much greater advantage of Minnesota's existing generation resources and could enable in-state nuclear power plants to continue operating for a least a decade longer than under a renewable energy standard," said EPRI Senior Technical Leader Dr. Nidhi Santen, who conducts research on energy systems, environmental policies, and electricity sector resource planning. "Our modeling showed that while an additional 3 gigawatts of interstate transmission capacity would be needed to meet the renewable energy standard, only 200 megawatts would be necessary under the technology-neutral policy."

A CLOSER LOOK AT TECHNOLOGY-NEUTRAL POLICIES

During the next Minnesota state legislative session in early 2020, the focus of policy discussions shifted from renewable energy standards to technology-neutral clean energy standards—in other words, policies that are less prescriptive about technologies permitted to achieve decarbonization goals. Great River Energy asked EPRI to conduct a follow-up analysis to delve deeper into the implications of a less prescriptive policy for Minnesota's electric sector.

EPRI researchers again used the US-REGEN model to characterize the outcomes of three increasingly stringent clean energy standards, in which 60%, 80%, and 100% of Minnesota's load uses carbon-free energy resources by 2050. For all three scenarios, researchers added a few restrictions to reflect on-the-ground realities in Minnesota:

- Carbon capture and storage would not be deployed due to a lack of suitable geological reservoirs.
- Wind and solar capacity would be capped at 10 gigawatts and 6 gigawatts, respectively, to reflect siting and permitting constraints.
- New nuclear plants would not be built because they are banned by state law.

All scenarios also assumed that no hydrogen-based generation would be built because it is still a nascent technology. The 100% standard had an additional restriction: fossil generation capacity would not contribute to the state's backup capacity beginning in 2050.

The analysis revealed that Minnesota can cost-effectively meet the 60% and 80% standards by using existing in-state wind resources, by expanding in-state wind and solar generation, and by extending the operations of in-state nuclear power plants. However, the 100% standard would be much more costly because the state would be unable to meet all its load using the technologies examined in the scenarios. It would require significant investments in a combination of new carbon-free generation resources, transmission, and load-reducing technologies—such as demand response and advanced, high-efficiency heating and cooling. Deployment of about 6 gigawatts of battery storage by 2050 could help the state comply with the standards more cost-effectively by reducing the need for natural gas generation and for load-reducing technologies (in the 100% scenario).

"We found that Minnesota's existing zero-carbon fleet can play a key role in meeting 60% and 80% clean energy targets," said Santen. "But under a 100% target, we could not find a cost-effective pathway to meet the state's load in the absence of nascent technologies such as carbon capture and storage, advanced nuclear power, and hydrogen."

"This analysis begins to shed light on the future states of energy policy in Minnesota and helps us understand the effects of those policies on the design of generation portfolios and energy resource options," said Ruzycki. "Research of this type is incredibly important for utilities, legislators, and policy-makers to more deeply understand the relative costs and benefits of various policy alternatives and how those policies may—or more importantly—may not impact decarbonization."

Great River Energy recently announced plans to phase out its remaining coal resources and add significant renewable energy, reducing the CO_2 emissions of its direct power generation resources by 95%.

"A key insight from this research is that the more a decarbonization policy broadens technological options, the less it may cost to reach the targets," said Dr. John Bistline, an EPRI expert on the analysis team who conducts research on the economic and environmental effects of policies and technology development. "To help balance high levels of renewable energy, it's important that utility planners have the ability to select the most cost-effective, technically suitable technology from a diverse set of options, such as energy storage, dispatchable nuclear power, and fossil generation with carbon capture. This insight is potentially generalizable to other states and can inform utilities, policy makers, and regulators across the country as they consider various decarbonization pathways."

KEY EPRI TECHNICAL EXPERTS

Nidhi Santen, John Bistline, David Young

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