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# A Focus on Battery Energy Storage Safety

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EPRI JOURNAL

# A Focus on Battery Energy Storage Safety

*As lithium-ion batteries scale, mitigating the risk of fires becomes more important*

***By Chris Warren***

Projections about the future growth of energy storage are eye-opening. For context, consider that the U.S. Energy Information Administration (EIA) reported that 402 megawatts of small-scale battery storage and just over one gigawatt of large-scale battery storage were in operation in the United States at the end of 2019.

By 2023, however, the EIA forecasts an additional 10 gigawatts of large-scale batteries will be installed in the United States. Globally, investments are pouring into energy storage projects, with projections putting the total market size for batteries at nearly $27 billion by 2028.

The fundamental reason for this big upswing in investments and deployments of energy storage is clear. As the global electricity mix adds large amounts of generation from variable sources like wind and solar, battery energy storage is crucial to reliably deliver electrons when the sun isn't shining, and the wind isn't blowing.

As battery energy storage grows in scale and importance, the need to ensure that these systems are designed, installed and operated in as safe and environmentally responsible a manner as possible also increases. As battery storage systems today overwhelmingly utilize lithium-ion technology, the industry must take steps to prevent and mitigate potential fires and preparing effective responses for the rare instances when they occur.

EPRI's battery energy storage system database has tracked over 50 utility-scale battery failures, most of which occurred in the last four years. One fire resulted in life-threatening injuries to first responders. These incidents represent a 1 to 2 percent failure rate across the 12.5 GWh of lithium-ion battery energy storage worldwide.

## COLLECTING THE DATA NEEDED TO ADDRESS FIRE RISKS

To better understand and bolster the safety of lithium-ion battery storage systems, EPRI and 16 member utilities launched the Battery Storage Fire Prevention and Mitigation initiative in 2019. The initiative is one of several EPRI-led efforts seeking to identify the root causes of battery failures and to improve and share knowledge about effective response strategies. These initiatives have included creating a battery storage fire safety roadmap, developing recommendations and leading practices for designing systems, and training and working with first responders responsible for putting out fires.

The work seeks to provide research-informed education to the owners and operators of lithium-ion batteries and to first responders. In that task, EPRI and its partners have an important advantage. "There are a lot of industries that deal with explosive things. We have very well understood methods of managing explosion hazards," said Dirk Long, a principal technical leader at EPRI, who is spearheading much of the research. "But nobody was looking at explosion hazards when most of these systems were built. People haven't been pointing their brains at the right problems and haven't had good data about how to solve them. This work is meant to address that."

The research is also meant to provide utilities with the information and tools they need to be comfortable with lithium-ion technology. "When utilities see these fires, they ask whether they should even use lithium batteries," Long said. "I think that's the wrong response. It's a matter of taking all the lessons learned, paying attention to the right problems, and solving them in our industry."

For example, the automotive industry has recognized the importance of system designs that prevent a single-cell thermal runaway from propagating. This lesson has become an industry-leading practice and was added to the latest UL standards for electric vehicle battery packs. "That is a type of systems thinking built on a decade of lessons learned in that industry," Long said. "We can pull that learning into the stationary energy storage market."

## UNDERSTANDING THERMAL RUNAWAY

EPRI's work is primarily focused on preventing failures and responding to them effectively if they occur. To do both of these well, it's vital to understand what can cause lithium-ion battery explosions and fires. "The fundamental cause of the hazards we worry about with lithium-ion batteries is thermal runaway," Long said.

At the most basic level, thermal runaway in a lithium-ion battery occurs when a failure of some type leads to overheating inside the battery cell. "It's the electrochemistry decomposing in its own kind of way that generates a lot of heat and creates a self-accelerating reaction," Long said. "It may cause fires, and it releases a lot of gases that are flammable and can cause explosions." Past EPRI research identified four root causes of thermal runaway: internal cell defects; faulty battery management systems, including bad hardware or software; insufficient electrical isolation; and environmental contamination from things like humidity and dust.

Much has already been learned about how to reduce the risk of thermal runaway. For example, EPRI conducted eight site visits to lithium-ion battery storage projects in the United States. The sites included systems being designed, under construction, and already operational; the systems varied in size from 0.3 MW/0.6 MWh to 182 MW/730 MWh. EPRI's safety review of these sites included analysis of data (design documents and equipment certifications), site walkthroughs, and assessment based on fire hazard mitigation guidance from the Energy Storage Integration Council.

Based on those assessments, EPRI developed lessons learned and guidance about steps that could be taken to improve safety. "We found that even though utilities had a lot of awareness around safety concerns, each one had a number of site design features that could be retrofitted to improve safety," Long said.

The findings of this research include the following.

Safety evaluations are influenced by subjectivity—There is a fundamental difference between evaluating a battery system to understand its performance and failure modes, and conducting a safety evaluation. Performance and safety vulnerabilities can be analyzed objectively using quantifiable data. By contrast, safety evaluations are inherently subjective, guided by factors such as the evaluator's experience and expertise, the system owner's tolerance for risk, and interpretation of safety-related data. The roles of those assessing safety also influence their perspective and priorities. For example, some fire protection professionals are experienced in hazardous material fires, while others have specific experience with safety events involving lithium-ion or other battery storage chemistries. To maximize safety, it is important to match the expertise and experience of those completing safety evaluations with the system design and technology at individual sites. Doing so also reduces the time required for an evaluation because the experts involved are already familiar with potential safety vulnerabilities and the possibility of missing risks.

Ownership models determine safety management and responsibilities—Clear lines of responsibility enhance the safety of battery energy storage systems. In assessing multiple storage system sites, however, EPRI observed that differing ownership models cloud safety management responsibilities. Adding to the confusion, large battery systems are often operated by a mixture of vendors and owners, which can blur responsibility for taking steps to mitigate safety risks. Clearly understanding and communicating safety roles and responsibilities are essential to improving safety.

Common safety data support a common evaluation process—The optimal approach to assess the safety risks of a battery energy storage system depends on its chemical makeup and container. It also relies on testing each level of integration, from the cell to the entire system. In addition, it's important to apply the appropriate safety testing approach and model to each battery system. For example, one of the EPRI assessments determined that an incorrect data set was used in safety testing; the data used represented a different battery module than the one to be installed at a site. When the proper data were used, new explosion risks were found, which necessitated a redesign of the battery enclosures.

Planning for failure requires decisions about acceptable levels of damage—It is impossible to completely eliminate the risk of a battery system fire. Steps to mitigate the chance of a fire or explosion inevitably involve choices and trade-offs. A recent EPRI study looked at the cost of safety design features in relation to a system's total cost of ownership. Some owners may accept the possible failure of a system and its components as well as the costs of cleanup necessary after an event rather than bearing the expense of additional safety measures. Others may decide that the possible loss of storage capacity and the expense of cleanup compel greater investments in mitigation and prevention.

## RESPONDING TO FIRES AND OTHER SAFETY-RELATED EVENTS

Taking steps to prevent thermal runaway can reduce but never fully eliminate the potential of its occurrence. "There's always a non-zero risk that a battery will enter thermal runaway, even if it's a really low risk," said Stephanie Shaw, a technical executive at EPRI whose research focuses on assessing and reducing the environmental and health impacts of energy generation and storage. "You also have to always be looking at what comes after and managing all the outcomes from that kind of failure." Shaw's research has explored topics such as the composition of combustion air plumes, the water used to extinguish battery fires, and the potential risks to first responders and the public from those releases.

To help maximize the effectiveness of response to fires and other safety incidents, EPRI hosted a workshop with utility representatives, researchers, first responders, and fire safety experts. The aim was to gather insights and leading practices to inform how different stakeholders should communicate and prepare for possible safety incidents.

The resulting report, *Proactive First Responder Engagement for Battery Energy Storage System Owners and Operators*, outlines actions to improve safety while also speeding the deployment of projects and lowering their costs. The recommendations all focus on steps to be taken before battery storage systems are installed or before they begin operation.

The recommendations are wide-ranging and include guidance on an overall approach to the leading practices to follow. They apply to stages from procurement through installation, as well as to both learning from and training first responders about some of the unique challenges of battery fires.

A few of these recommendations are summarized below.

> Open communication during the storage system design phase—Close collaboration and communication between first responders and battery energy storage owners and operators is always important. It should begin well before installation of the system begins. Often, it only starts during the permitting process, when designs and plans for construction may already be complete. This is a lost opportunity. When dialogue begins earlier, first responders can provide input about the most effective fire suppression and containment systems as well as direction on the ideal distance between battery systems to avoid propagation of a fire to other units and containers. First responders can also educate utilities about their typical response protocols. This information can then be integrated into incident response systems. Other guidance covers development of utility expertise on battery safety and completion of a comprehensive safety evaluation at each storage system facility. Another important leading practice is for utilities to identify a safety lead at each battery site. This gives first responders a knowledgeable contact to communicate with if an incident occurs.
>
> Smart design and an emergency response plan—Firefighters need reliable access to water. Other design features to consider include the presence of multiple alarm systems in case one fails; limits on charging and discharging levels as well as well-defined temperature and voltage ranges; and clear signage showing the location of emergency disconnect switches. Additionally, an emergency response plan that details the procedures for shutting down the battery storage system avoids confusion and risky delays in response.
>
> Collaboration with and help training first responders—Firefighters need to be aware of the design of a battery storage system and the layout and fire protection systems in the facility where it's installed. The owners and operators of battery energy storage systems should proactively ensure that first responders have that information and should actively solicit their feedback. Storage owners should also make battery storage experts available to first responders and provide ongoing training to help ensure they are prepared in case of an incident.

The main takeaway from the engagement with utilities, first responders, and the owners and operators of storage systems is to be proactively and continuously collaborative. For utilities and storage owners and operators, it's also important to listen. "It's important to help train first responders, but more importantly to be trained by them, because they have insights and practices from responding to fires that can apply here and protocols that must be followed," Shaw said.

EPRI is currently working on a range of resources to help improve the safety of battery energy storage systems called the *Project Lifecycle Safety Toolkit*. It will include everything from data sets to white papers and guidebooks that provide practical steps to mitigate the risk of a battery fire and to optimize the response in case it occurs.

"These are about helping the industry take the first step towards safety," Long said. "Most of the problems we know how to solve if you get people started on it. We think that once you get enough smart people pointing their brains at the right problem, they'll be able to solve it collectively."

## EPRI TECHNICAL EXPERTS

Dirk Long, Stephanie Shaw

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# Understanding the Price of Flexible Operations

*As more and more variable generation comes online, a new EPRI tool quantifies the costs of operating thermal generation more flexibly*

***By Chris Warren***

It's hard to overstate how dramatically renewable generation has grown over the past decade. According to the International Energy Agency (IEA), the cumulative global installed renewable electricity capacity in 2012 was a little over 1500 gigawatts—most of it hydropower. By 2021, a combination of policy support, steady cost and technology improvements, and increasingly urgent efforts to address climate change had resulted in record-breaking annual additions to renewable generation capacity.

According to the IEA, 2021 saw nearly 295 gigawatts of new renewable generation, primarily wind and solar. The IEA forecast 2022 would be another record year, with renewable additions reaching 320 gigawatts despite supply chain challenges and inflation that has caused solar and wind prices to rise recently.

While additions of renewable energy are important to address climate change, they also raise questions about the steps necessary to maintain grid reliability. Questions of escalating importance as society looks to electricity to power transportation, heating and cooling, and a growing list of industrial operations. Indeed, as electrification becomes more critical to a decarbonized economy and society, grid reliability becomes increasingly paramount.

## FLEXIBLE OPERATIONS STRESS THERMAL POWER PLANTS

As variable generation sources increase, one of the most pressing questions is: What are the potential impacts on existing thermal generation assets? Many of these assets, including natural gas- and coal-fired power plants of different sizes and turbine types, are already operating differently than they were designed to do. For example, the influx of variable generation resources and changes to energy markets have forced many baseload fossil fuel plants to cycle frequently and operate in a load-following manner.

These new modes of operation place stress on thermal assets fundamental to maintaining grid reliability. Significantly, they can also elevate the possibility of expensive and disruptive unplanned outages. "As we continue to transition to this clean energy future where we have more variable renewable energy, the demands on thermal dispatchable assets to perform effectively when the sun isn't shining and the wind stops blowing is very high," said Stephen Storm, an EPRI technical executive. His research focuses on fleet generation optimization. "We depend on them for frequency controls and to be able to turn on and off reliably and as efficiently as possible."

But for utilities charged with maintaining grid reliability and prioritizing operations and maintenance (O&M) investments, moving to more flexible operations can be an argument against funding upkeep and maintenance of thermal assets. "It can be very difficult to show that you need increased budget dollars or need to fund projects when you are generating fewer dollars in megawatt sales," Storm said. "Instead, folks in charge of budgets may say you're getting 30% less than you did last year because you generated fewer megawatts."

## THE COST AND UNCERTAINTY MANAGEMENT TOOL

Past revenue and other metrics don't accurately reflect the risk of equipment stress and damage and unplanned outages from flexible operations. It's far better to base investment decisions on a quantifiable assessment of the costs of increased cycling. That was the idea behind the development of EPRI's Cost and Uncertainty Management Tool, which was released late in 2021 and is already being used by utilities worldwide.

The tool is designed to quantify the costs of flexible operation via frequent cycling for eight different gas- and coal-powered plants and also forecast both equivalent forced outage rates and the incremental costs of increased flexible operation. The tool builds on and improves an existing simplified cost model and seeks to expand the traditional understanding of the economic and reliability impacts of plant cycling.

Last year, EPRI completed a study examining 40 years of degradation data from the North American Electric Reliability Corporation Generator Availability Degradation System (NERC GADS) and found that boiler tube leaks were consistently the number one reason for failure in conventional steam plants. Increased cycling affects individual power plants differently—combined-cycle units are far more flexible by design than conventional steam units—but a more comprehensive view of the costs of cycling takes the following factors into account:

- **More maintenance and overhaul costs**—When plants cycle more frequently, the capital costs of maintenance and overhauls needed to avoid unexpected outages go up.

- **Outage recovery**—Getting units back up and running after a forced outage can be expensive. Those costs add up when cycling increases the number of unplanned outages. More frequent outage recovery can also introduce the potential for operator errors, increasing O&M expenses. Paying for generation to replace units during an outage is another expense.
- **Increased heat rates**—When units cycle more often and components degrade, there can be a long-term reduction in efficiency.
- **Startup costs**—Unit startup requires extra fuel, electrical power, and chemicals. When cycling demands more frequent startups, these costs add up.
- **Shorter unit life**—Ultimately, flexible operation demands shorten a power plant's productive life, and utilities may need to pay for additional capacity.
- **Engineering and management costs**—Effective, flexible operation isn't based on guesswork. Potential modifications and upgrades that allow units to cycle require study and analysis, which take time and financial resources. There are also costs associated with dispatching units to load to follow or take advantage of market opportunities.

## ADDITIONAL INPUTS DELIVER ADDITIONAL INSIGHTS

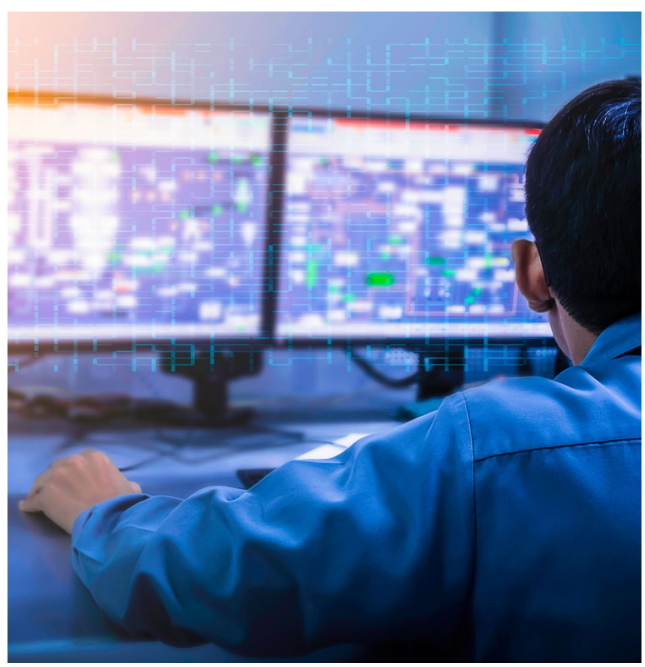
The tool relies on a mixture of qualitative and quantitative inputs to project a forced outage rate and the costs of increasing the flexible operation of fossil units. For example, the tool incorporates historical data about a unit's non-fuel O&M, capacity factor, heat rate, number of starts, operating hours, and generation. In addition, it integrates projections about a unit's retirement date as well as the number of starts, operating hours, and generation.

Some of the inputs have nuance. For instance, not all starts have the same potential impact on plant components. "A unit may have been cold and sitting offline for two or three weeks, or it could be hot, and it just came offline yesterday because of economics," Storm said. "The degradation and potential damage from those different starts are going to vary based on the operating mode, whether it's cold, warm, or hot. And in some cases, hot starts may be more damaging to specific components than cold starts."

Using the tool can give utilities some critical insights that can help guide future budgeting. For example, one output could be that each hot startup costs $41,000 in fuel and potential damage, while each cold startup costs $96,000. Those costs could then be used to forecast the annual expenses of starting a unit based on how flexibly it will need to operate. "You can look at a scenario where the historical cost of starts was $400,000 a year, but now it's up 366 percent because of some change in the energy market," said Storm. "Now the expected startup costs are going to be $1.8 million, which is huge if you only have an O&M budget of $2 million."

These projected data can be helpful in making what are obviously complex decisions. For instance, imagine that a unit is supposed to be retired in five years and is being operated in a way that may lead to more forced outages. In that case, retiring the unit early may make more sense than paying for the necessary upgrades and maintenance.

The tool can also help decision makers grasp how proactive maintenance to prevent a forced outage can increase revenue. "Let's say a utility does an asset integrity audit after using the tool and finds that it should fix some boiler tubes near the end of their useful life, or maybe it needs to upgrade its gas



turbines," Storm said. "It could then say to senior management that it needs $2 million to fix this. Then, if it has a summer or winter where demand spikes, it won't have a forced outage that could cost $10 million in lost generating sales."

In addition to the Cost and Uncertainty Management Tool, another high-level flexibility assessment tool is already in use in the United States, South America, Australia, and Asia. For example, India's largest power utility, NTPC Limited, applied the tool at six of its power plants that have been particularly challenged by flexible operations. The plants account for 9 gigawatts of the utility's total generating capacity of >55 gigawatts and have been tasked with operating more flexibly as more variable generation from renewables comes online. The tool has helped NTPC pinpoint flexibility limitations and prioritize investments that will enhance flexibility while maintaining reliability, safety, affordability, and environmental responsibility.

While it's important to identify and quantify the potential costs of forced outages and the investments needed to avoid them, it's also critical to understand how to address possible vulnerabilities. Another ongoing EPRI project will create a handbook of failure mitigation strategies to guide actions at individual units. The handbook will be released later in 2022.

"What we are doing is trying to optimize asset management under flexible operations. What are the failure mechanisms utilities are seeing? What is the frequency of those failure mechanisms? Are these short- or long-term issues?" Storm said. "We will take the understanding of issues or vulnerabilities and develop strategies that can address them in a practical way to enhance site defense strategies."

## EPRI TECHNICAL EXPERTS

Stephen Storm, Michael Caravaggio

# A Framework to Navigate Climate-Related Water Risks

*A three-year EPRI research initiative provides tools for energy companies to understand and adapt to water resource challenges*

***By Chris Warren***

In some respects, the Wabash and San Juan rivers are quite similar. From its headwaters in the west of Ohio, the Wabash flows about 765 kilometers through Indiana and along the border with Illinois until it joins up with the Ohio River near where Illinois, Kentucky, and Indiana meet. The San Juan River runs 616 kilometers from southern Colorado through northwestern New Mexico and southeastern Utah before reaching the Colorado River. But the similarities of the Wabash and San Juan rivers more or less end with their length and the fact that both traverse multiple states.

The Wabash River Basin is largely flat, made up of farms growing corn and soybeans. Precipitation is plentiful. In fact, since 1895, Indiana—where most of the river basin is located—has seen its average annual snow and rainfall increase by about 15 percent. By contrast, the 38,000-square-mile San Juan River Basin is a study in extremes, combining tall mountains and flat valleys. Though the basin is extremely dry overall, its mountainous northeastern regions receive up to 60 inches of precipitation each year, while the southern and central portions get an average of only 10 inches; some of the hotter and drier areas experience years of no precipitation at all.

## A CHANGING CLIMATE AND AN ONGOING RELIANCE ON WATER

The Wabash and San Juan river basins have something else in common; however, temperatures and precipitation patterns are changing due to climate change. In the Wabash basin, changes are likely to include a general increase in annual precipitation, albeit with more extremely wet and unusually dry years. Flooding could be more of a challenge at times, as could water quality issues due to higher water temperatures. The San Juan River Basin is increasingly subject to extreme drought conditions that drastically reduce the availability and flow of water throughout the region.

*Wabash River*

Climate change is impacting river basins and water resources throughout the United States and around the globe. Understanding and planning for these changes is particularly important for the electric power industry. Indeed, there is a tight nexus between water availability and the operation of electric energy companies. For example, reliable access to water is critical to cool many fossil fuel and nuclear power plants. Hydropower plants directly rely on water to generate electricity. And many regulatory compliance issues are connected to how utility operations impact water quality.

Rising global temperatures and increasingly frequent extreme weather events associated with climate change are already altering how energy companies need to plan and operate. For instance, companies that depend on hydropower to supply electricity to customers must adjust their strategies for meeting demand in the face of decades-long droughts. Already, Hoover Dam's energy capacity has been reduced 25 percent as a result of record low (and still dropping) water levels at Lake Mead, which, like the San Juan, is part of the Colorado River Basin. Other water-related challenges energy companies face include ensuring some power plants are designed to withstand storm surges and floods and avoiding damage to dams and levees during extreme weather events.

Equipping energy companies with tools and a framework to understand and plan for climate-related changes to water resources has been the focus of three years of wide-ranging research recently completed by EPRI. "When we started this work, a big driver of it was that there was no way to look at how climate-based projections interfaced with hydrologic models and how to make decisions," said Nalini Rao, principal technical leader at EPRI. "Companies want to know the risks and also what to do about it."

To provide the framework and guidance energy companies need, EPRI focused its research on three areas. One was evaluating the climate and water data and models available to grasp possible changes to water resources. Another was how energy companies could take what they learned from models and data to understand better the risks they faced. The third was adaptation strategies energy companies could implement to effectively manage climate-related changes to water resources.

As part of the research initiative, EPRI also conducted pilot studies identifying and quantifying water-related risks to the power industry in the Wabash, San Juan, and Allegheny river basins. The three river basins were intentionally selected for their varying geographic locations, topographies, and precipitation patterns.

## EVALUATING MODELS

A foundational step in the research was examining the many models energy companies could use to assess how climate change may impact water quality and availability. In 2020 EPRI released the resulting report, *Evaluation of Hydrological Models for*

*Climate-Based Assessments*. In total, EPRI evaluated 22 models using a range of factors, including the models' complexity and their ability to model extreme events and to produce outputs relevant to the power sector, such as estimated stream flow and flooding. Another criterion was how easy or difficult it would be to apply models to specific geographic regions – an important factor, given that energy companies have defined geographic service territories.

The next step was to apply similar water resource and climate models to real-world conditions in the Wabash, Allegheny, and San Juan river basins. The two models selected for the analysis were the Watershed Assessment Risk Management Framework (WARMF) model and the Soil-Water Assessment Tool (SWAT). WARMF and SWAT were chosen because they are able to model both hydrology and water quality, are free and widely available, and can model many of the potential implications of climate change, such as flooding, drought, and low water flow conditions.

These two water resource models also incorporate projections of future climate conditions through the end of this century provided by general circulation models (GCMs). The GCMs selected for the pilot projects were chosen for their accuracy in reproducing past water conditions and their ability to produce future projections based on two future climate scenarios: one with a modest amount of regulation of greenhouse gas emissions and another with no regulation or reduction of emissions. Other selection criteria were how easily researchers could apply model results to local conditions – a process known as downscaling—and whether these downscaled data products were already available.

The selected tools were applied to the three river basins to quantify the potential water risks of a changing climate. For example, in the Wabash River Basin, researchers looked at the potential for more frequent floods and impacts on freshwater mussel habitat due to more severe and frequent drought conditions. In the Allegheny River Basin, the models were applied to understand better how a changing climate could affect thermal generation facilities due to the increasing temperatures of source water used for cooling. The research results are included in the EPRI report *Quantifying Potential Impacts of Water-Related Risks Associated with Climate Change.*

## QUANTIFYING WATER-RELATED RISKS IN THE SOUTHWESTERN UNITED STATES

In the San Juan River Basin, the study looked at what extended, and extreme drought conditions could do to hydropower production. In particular, researchers examined what drought conditions could mean for the Navajo Dam Hydroelectric Plant in Farmington, New Mexico. The 30-megawatt Navajo Dam is one of four power plants providing electricity to the 45,000 commercial and residential customers of the Farmington Electric Utility System. The analysis utilized three versions of the SWAT model and incorporated GCM simulations of both modest emissions regulation and none.

*San Juan River*

*Allegheny River*

The results illustrate several potential water-related challenges faced by the owners of the Navajo Dam and other energy companies across the Southwest that rely on hydroelectric power. For example, the increased frequency and severity of drought in the region could lead to a reduction in stream flows and higher levels of water evaporation. Though there are differences in the scenarios produced by the different models, the impacts of ongoing drought could be lost revenue from electricity sales, increased utility costs to make up for generation not provided by hydropower, and higher customer rates.

Other conclusions from the analysis include the likelihood that the Southwest will continue to face hard choices about the use of water held in large reservoirs. For example, limited water supplies may require some crops requiring irrigation to lie fallow. Further, wind and solar development could increase across the region to make up for reductions in hydropower production because both generation sources are generally cheaper than coal, natural gas, and hydropower facilities.

## EFFECTIVE ADAPTATION STRATEGIES

The third important aspect of EPRI's research focused on steps energy companies can take to minimize some of the water risks posed by a changing climate. "Companies obviously want to know what risks they face, and the modeling helps provide that," said Jeff Thomas, an EPRI principal technical leader. "But they also need to know what to do about it and how much different approaches cost."

Several potential interventions are identified in the EPRI report *[Program on Technology Innovation: Minimizing Risks to the Electric Power Industry from Changing Water Conditions](#)*. The approaches aim to mitigate risk through actions that reduce the impact of floods, restore natural water flow, improve water quality, and lessen stream erosion. Strategies evaluated included the construction of bankfull wetlands, which involves removing several feet of sediment from a floodplain. This frees up space that could be used to store water during times of flooding, which can create a wetland habitat.

Another strategy examined was the reintroduction of beavers to a watershed. The activity of beavers can profoundly impact the flow of water, including reducing erosion, improving water quality, and helping landscapes maintain moisture during drought. The study also looked at the potential impact of careful placement of log structures in small streams as a way to reduce erosion and create a more natural flow of water.

Researchers examined the effects different interventions could have in the San Juan, Wabash, and Allegheny river basins. The potential benefits identified are both significant and cost-effective. Overall, these measures would expand the amount of water storage available in each river basin. Expanded storage results in less erosion, decreased flood damage, higher water quality, reduced drought conditions, and other benefits.

In the Wabash River Basin, for example, the combined impact of constructing bankfull wetlands, reintroducing beavers, and placing logs could add 9.2 billion cubic meters of storage, which is nearly six times the existing storage volume. The same measures applied in the Allegheny and San Juan river basins have the potential to increase storage by 20 percent and 3 percent, respectively.

Taken together, the work to identify appropriate models, evaluate climate risks, and evaluate mitigation strategies is meant to provide energy companies with a framework to approach their own unique water resource challenges. “This study was not intended as an assessment for individual companies or to answer specific questions, although we are hoping to do work in the future that does just that,” Thomas said. “We wanted to create a framework energy companies could use to do their own assessments, identify their own risks, and understand their options for mitigation and adaptation. There are so many decisions about which models to choose, how to downscale them for a region, and what metrics matter. Building a framework provides a pathway to navigate this world of options.”

## EPRI TECHNICAL EXPERTS

Nalini Rao and Jeff Thomas

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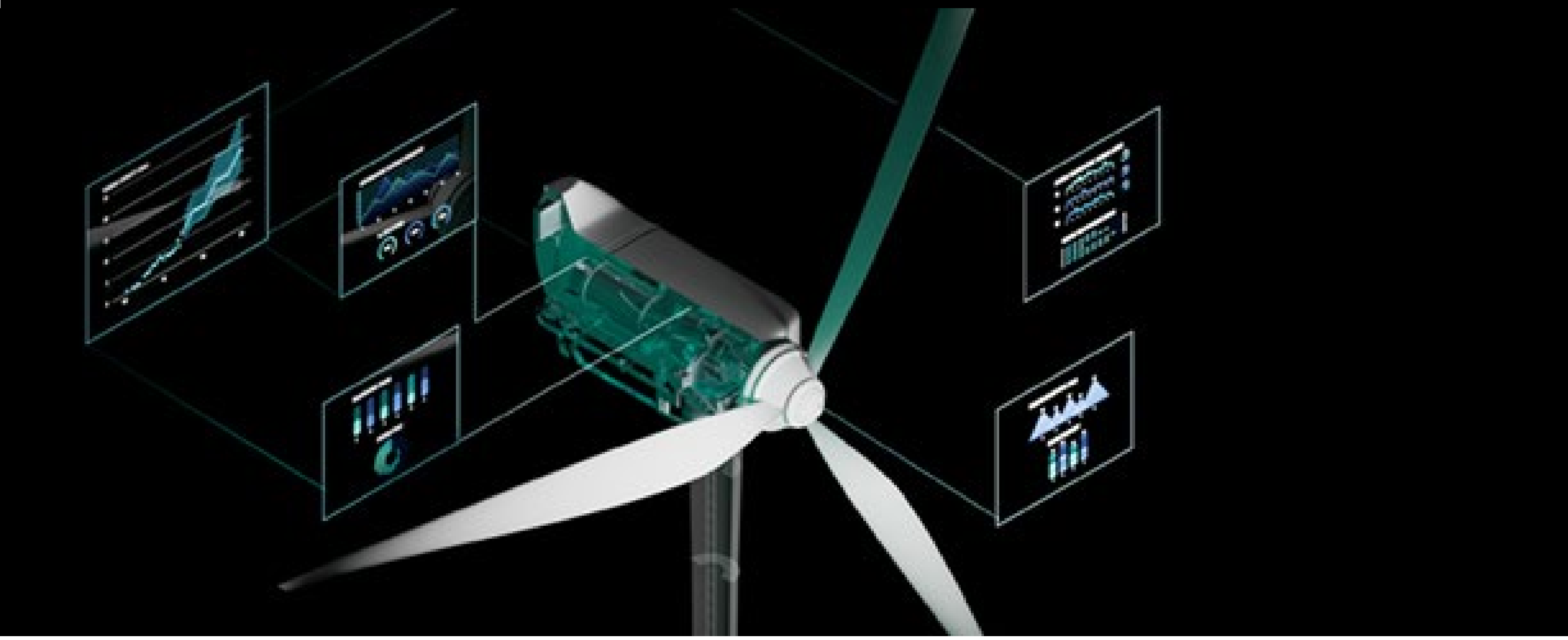


# Enhancing Wind Turbine Reliability

*A new web-based tool named WinNER uses reliability data to lower operations and maintenance costs*

***By Chris Warren***

The wind industry around the globe has grown enormously over the past two-plus decades. According to the Wind Vision report by the U.S. Department of Energy (DOE), there were about 2.5 gigawatts of wind capacity installed in just four American states in 2000. By July 2022, wind capacity had skyrocketed to over 140 gigawatts across 36 states.

Future growth projections for both land-based and offshore wind projects are also robust. The DOE forecasts that by 2050, total wind capacity will surpass 404 gigawatts, with onshore and offshore projects in 48 states. As the wind industry continues to mature and plays an increasingly important role in powering a decarbonized society, avoiding unexpected outages has become an ever more vital priority.

Enhancing the reliability of wind farms and turbines—and being able to proactively address potential problems before they lead to unplanned outages—is essential if electricity is going to power transportation, heating and cooling, and an expanding list of industrial uses. But it is also critical to the operators of wind farms, who depend on continuous turbine uptime and predictable operations and maintenance (O&M) costs to maximize revenues.

For example, unscheduled fault-driven events and downtime can drive over 60 percent of land-based turbine O&M costs. That share is equal to one-third of overall operational expenses. Equipment failure that necessitates replacements can also be very expensive and can lead to prolonged turbine downtime. For instance, installing a new gearbox can cost upwards of $400,000, and a generator can cost between $100,000 and $225,000.

## THE WIND NETWORK FOR ENHANCED RELIABILITY (WINNER) TOOL

Understanding, identifying, and proactively addressing the factors that reduce turbine reliability motivated the development of the Wind Network for

Enhanced Reliability (WinNER) web-based tool. "What are the challenges in the wind industry? Obviously, number one is the increase in operations and maintenance costs that come from wind turbine usage," said Dr. Raja Pulikollu, an EPRI principal technical leader. Pulikollu has spearheaded the development of WinNER and other wind reliability research at EPRI.

According to Pulikollu, EPRI's research has two primary objectives. "Number one is to find the reasons for turbine failure. Why are systems failing, and what are the failure modes?" Pulikollu said. "The second is to help operators pick the right suppliers of the major systems and components like the blades, pitch bearing, main bearing, gearbox, generator, and turbine models by looking at reliability data. That is what we do with the WinNER tool."

## USING DATA TO MAKE BUDGETING AND PROCUREMENT DECISIONS

Even though the wind industry has matured quickly, it is still relatively young. In the industry's early years, the focus was almost entirely on turbine uptime. "When wind turbines got momentum around 2007, most of the attention was on how to keep the turbine up and running," Pulikollu said. "Turbine operators wanted their availability to be higher because the more power they generated, the more money they earned."

Complexity has been another factor limiting the attention paid to reliability. For example, not only are there at least eight gearbox suppliers, there are also half a dozen suppliers of bearings that go into the gearbox. Other equipment that goes into wind turbines and farms has similarly diverse collections of components and suppliers.

What has historically been lacking are data. In particular, data that could connect everything from specific components and suppliers to the geographic location of wind turbines simply haven't existed. Wind farm operators have had to make procurement and O&M decisions based solely on their experience. "Some operators would allot millions for O&M purely based on experience. Not much was driven by data," Pulikollu said. "Once you have data in hand, there are many levels where you can gain value from it. One is your existing fleet supplier selection, but you can also improve inventory management and equipment selections for future farms. Data is what allow you to move away from experience-based reliability estimation."

When Pulikollu joined EPRI in 2017, he began the work of assembling, standardizing, and digitalizing the data necessary to build WinNER. This required the creation of a database that stored a wealth of information about wind turbine deployments. Data collected on individual turbines include where they are located, where they were manufactured, when they were installed, and who supplied major components. "If something failed, we collected information about when it failed, when it was replaced, which component failed, what the failure mode was, and how the damage was detected," Pulikollu said.

The database now holds data from more than 10,000 turbines totaling 20+ gigawatts of installed capacity. These include turbines made by seven different original equipment manufacturers (OEMs) with ratings ranging from 1 to 4.5 megawatts, as well as major systems made by multiple manufacturers. The database also includes thousands of data points about system failure, which can be used to develop reliability and health monitoring models.

## WHAT DATA SAY ABOUT THE CAUSES OF PREMATURE FAILURE

The data collection and analysis that have gone into the development of WinNER have already surfaced important lessons about turbine and component reliability. Among these are the specific factors that cause premature failures. The top four causes of failures are:

- **Issues with manufacturing quality.** As the wind energy market has expanded, so too has the demand for low-cost turbines and other components. Meeting that demand, however, can result in equipment defects that reduce reliability. “You have OEMs trying to reduce costs to meet the demands of industry,” Pulikollu said. “And if you do that, you may give up quality.”
- **Improper load design.** Bearings, gears, and other components have to be designed properly to maintain high reliability. Improper designs result in non-uniform loads and stresses that can hamper reliability and result in failures.
- **Inadequate maintenance.** The way operators approach maintenance significantly impacts the reliability of wind turbines and farms. Is a turbine proactively maintained, or is maintenance deferred until the turbine fails? Not surprisingly, the data show that more proactive maintenance results in higher reliability.
- **Variable wind characteristics.** Wind farms are understandably located in places where the wind resource is reliable and robust. But wind characteristics vary considerably from one location to another and with the proximity of other wind turbines and farms. “Is my farm located in a high wind region subjected to high turbulence intensity? Or are there neighboring wind turbines and/or farms causing wind wake on my turbines that result in higher loads and lower reliability?” Pulikollu said.

The collection of data to develop WinNER has also surfaced other insights about the causes of equipment failure. In the first seven years of a turbine’s operation, for instance, defects in materials and design, as well as other internal factors, are the primary causes of failure. After seven years, however, external factors like a farm’s location, wind characteristics, and maintenance strategies are the primary drivers of turbine major systems failure.

## DIFFERENT VIEWS OF RELIABILITY

More than 20 gigawatts of data provide a lot of insights and lessons about wind farm reliability. WinNER also provides wind farm operators both granular and macro perspectives on reliability. It provides four different views:

- **Industry-wide.** Because WinNER's database includes reliability metrics from such a wide range of wind farm types, turbine models, sizes, and locations, it can demonstrate how reliable the industry is as a whole and whether or not reliability is improving.

- **Across WinNER member fleet.** Operators can use WinNER to assess the overall reliability of their fleets. A member can first examine reliability data about the turbines and components installed at its own wind farms. Those data can then be compared to aggregated anonymized data in WinNER to benchmark reliability against other operators with similar fleets. These comprehensive WinNER data assist operators with O&M budget forecasting, identification of wind farms with higher-than-average failure rates, inventory management, and resource planning.

- **Turbine level.** Utilities and plant operators using WinNER can also gauge the reliability of specific turbine makes and models in their fleets. Reliability data about the actual turbines they're operating can provide insights to inform O&M budgets. Operators can also use the data to benchmark their turbine reliability against that of fleets with similar turbine makes and models and to schedule more preventive maintenance.

- **System level.** WinNER provides reliability data about a range of wind turbine systems/components. For example, users can view reliability data about specific blade, gearbox, and generator makes and models, failure locations, and damage modes. These system-level reliability data assist operators in identifying critical components, selecting suppliers, identifying and rectifying serial defects, and upgrading components.

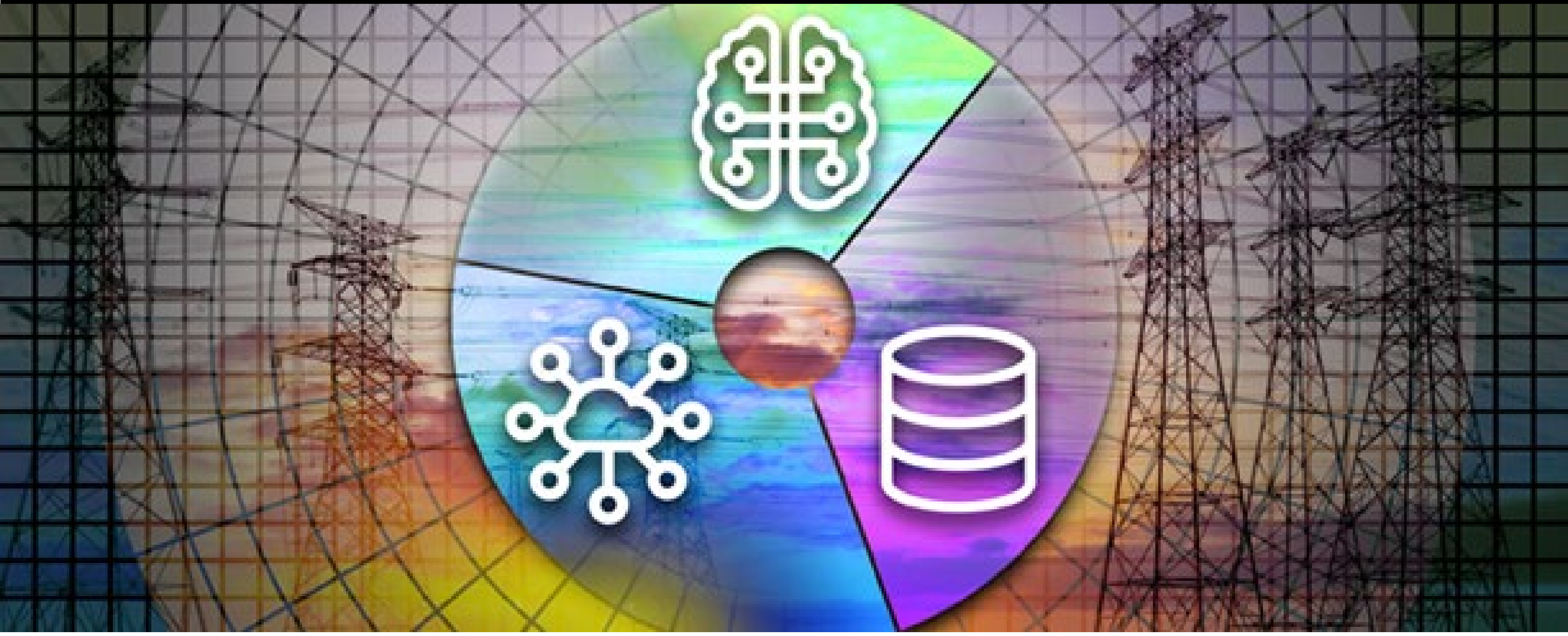
More than 25 utilities/operators have been participating in WinNER and gaining value at multiple levels reducing their O&M costs. For example, Duke Energy, Portland General Electric (PGE), and Xcel Energy use WinNER to forecast future failure rates and to plan O&M budgets. "Duke's collaboration with EPRI on the WinNER platform has enabled better insights into major component health and reliability across the fleet through benchmarking and understanding our platforms in comparison with industry failure rates," said James Bezner, director of performance services for Duke Energy Sustainable Solutions. “The WinNER platform, paired with Duke's in-house major component predictive capabilities, has led to an improved understanding of the health and risk of these components and a reduction in failure rates enabled by early detection and mitigation of catastrophic failures.”

EPRI is continuing to expand the value of WinNER. That effort currently includes collecting the data necessary to identify the causes of damage to turbine blades, main bearings, and pitch bearings. EPRI is also developing physics-based machine learning models that can proactively identify major system/component damage by examining historic operations and loading cycles.

The ultimate aim of the wind turbine health monitoring models is to identify damage in its early stages, before it results in a failure. “That is where early damage detection comes in and where replacing critical components with better products comes in,” Pulikollu said. “We want the turbine failure rate to come down, reducing O&M costs and increasing production revenue.” EPRI technologies provide $1 million in value per year at a typical wind farm. “Supplier selection based on reliability reduces future O&M costs at a typical wind farm by $2 to $4 million,” says Pulikollu. “This is based on turbine systems and components that can last for the remaining 15 to 20 years with no further full replacements.”

## EPRI TECHNICAL EXPERTS

Raja Pulikollu Ph.D.



# A Time for Coordination

*An EPRI-led working group develops methods for grid operators to enable grid services from distributed energy resources*

***By Chris Warren***

One of the most obvious manifestations of the energy transition is the huge amount of distributed energy resources (DERs) being integrated into the distribution grid. For example, U.S. energy storage capacity tripled in 2021, according to the U.S. Energy Information Administration. Though most of the new capacity was grid-scale, distribution system storage is also on the upswing. And while overall solar installations fell 24 percent in the first quarter of 2022, residential photovoltaics (PV) systems enjoyed their largest quarter in history.

The adoption of DERs is likely to accelerate, thanks to technology improvements, competitive pricing, and supportive policies and regulations. The recently passed Inflation Reduction Act provides long-term federal incentives for both energy storage and solar. An example of a state-level policy is New York's Climate Leadership and CTommunity Protection Act, which targets an emissions reduction of 85 percent from 1990 levels by 2050.

Equally important is the Federal Energy Regulatory Commission (FERC) issuance of Order 2222 in 2020. Order 2222 requires independent system operators (ISOs), transmission system operators (TSOs), and regional transmission operators (RTOs) to establish rules to allow full DER participation in wholesale capacity, energy, and ancillary services markets. In announcing the order, FERC said it was "a new day for distributed energy resources."

### DER SCALE DEMANDS COORDINATION

For distribution, transmission, and independent system operators, the growing influx of DERs presents opportunities to leverage a new type of resource to benefit the power system. At the same time, DERs can pose real challenges to power system resilience and reliability. Increasing levels of DERs also challenge distribution system operators (DSOs) and ISOs/RTOs to coordinate and optimize their management. As more and more DERs become operational and start delivering services to both wholesale markets and the distribution system, that need for coordination will only increase.

Unfortunately, there is no legacy of coordination to build on. "ISOs approach problems in the bulk power system in their own world, which is at the transmission level," said Ajit Renjit, Smart Grid Engineer at EPRI. "Distribution utilities approach their problems purely from the perspective of the medium- and low-voltage networks which they operate. The need for coordination has never existed."

DER aggregators are key stakeholders in this conversation about coordination. By aggregating DERs, they reduce the total number of individual solar, storage, and other DERs that need to be managed – a complex task, given the unique operational characteristics of different types of DER. Aggregators use control systems to abstract the complex capabilities of many DERs and present them as a simple, more manageable set of grid services to the grid operator.

In other words, aggregations of DERs can be managed much like a large power plant. "That is what the bulk market operator wants. They don't want to talk to individual devices. They want to talk to one virtual plant that is large enough to provide a necessary service to the bulk system," Renjit said. Under ISO market rules, DERs must have a minimum capacity to be eligible to participate—a threshold few individual devices can reach.

## A UNIQUE EPRI WORKING GROUP

In 2019, EPRI convened a working group that met weekly to facilitate TSO and DSO coordination discussions. The group included ISOs/RTOs, DSOs, DER aggregators, regulators, national research laboratories, academics, and others. Its work took on new urgency after FERC Order 2222 required wholesale market operators to develop rules enabling DER participation. The working group's goal was to establish a framework and document a menu of coordination functions that would enable DERs to provide grid services.

Coordination functions can be defined as the expected actions, responsibilities, and data exchanges of two or more parties that perform a function or sequence of functions cooperatively. Major drivers for coordination are to maintain reliable system operation and to quantify the value of services provided by DERs. "Reliability is a problem when DERs start participating in the wholesale market and distribution utilities don't have visibility into the operation of DERs following wholesale market signals," Renjit said.

Valuation is also a nettlesome challenge. For example, many solar PV systems participate in net metering programs with their local utilities. Soon, those same PV systems may have the opportunity to provide services to the bulk system. "Without proper coordination methods, the same DER may get used and compensated. The framework could determine that the DSO will use the DER services for a certain period, and then the ISO will use them. Or the DSO and ISO could each use 50 percent of the DER's capability."

ouble counted for a service and could wrongly be compensated twice," Renjit said. "A common framework needs to be established so DSOs and ISOs/RTOs can agree on how a DER asset will be

## THE BUILDING BLOCKS OF A FRAMEWORK

Earlier this year, EPRI released the *TSO-DSO Coordination Functions for DER* report, resulting from the working group's years of effort. The report is a comprehensive menu of information, controls, and monitoring interactions and functions that can be assembled to create a coordination framework suited to an individual region's rules and market conditions.

Besides developing a resource that acknowledges regional differences, the report recognizes that each entity involved with coordination has its own unique roles. "With this broad list of functions, one can build a framework considering each stakeholder's unique roles and responsibilities under a particular jurisdiction. That's the most important takeaway of this work," Renjit said. "The regulatory framework in every state is going to define what the framework can and cannot include."

The functions developed are also grouped based on the timeframe when they are likely to be relevant. For instance, some functions may be important in the context of a day-ahead or real-time market, while others are critical after a service has been provided to the bulk market for settlement.

The working group also addressed how ISOs/RTOs, DSOs, and DER aggregators actually apply the functions to develop the foundational technologies for coordination. "By specifying the roles and functions of a DSO or a bulk market operator or an aggregator, the work provides them the guidebook to specify requirements and design the planning and operational tools to make it work," Renjit said.

## THE ROAD AHEAD

A significant amount of work still needs to be completed to improve TSO-DSO coordination. For instance, DSOs need new capabilities, such as DER management systems (DERMS) and upgraded back office systems, to ensure reliable system operation when DERs are enabled to provide grid services. Utilities should also update their DER

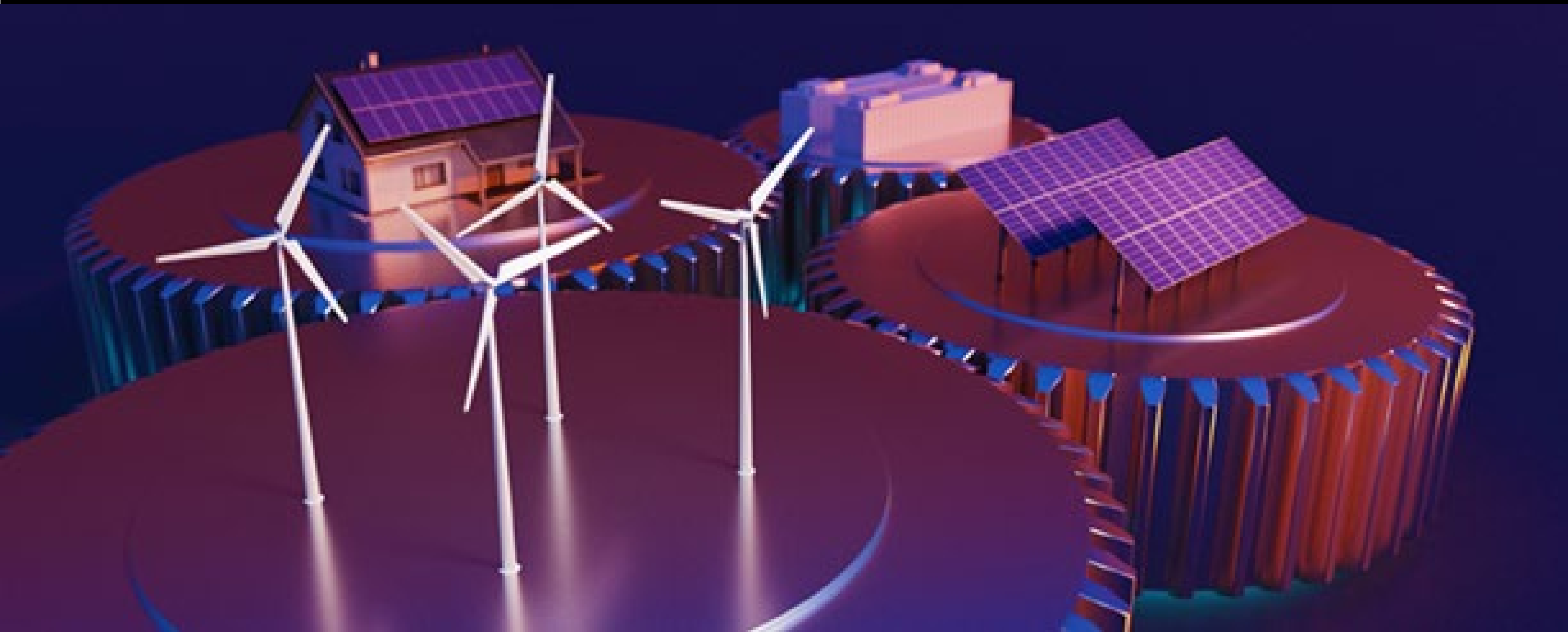
interconnection practices to determine the impacts of DERs providing grid services to the bulk system operator. Rules need to be in place to manage DERs equitably when they violate the operational limits of the distribution system and also to value the services they provide.

As ISOs and DSOs prepare to implement the requirements in FERC Order 2222, a major question of what constitutes a successful coordination framework still exists. EPRI's ongoing work will provide guidance for selecting and developing these new frameworks by determining the benefits and limitations of various options. This includes asking questions about the cost and complexity of a DERMS or distribution management system, fully grasping how complex and frequent communication between aggregators and ISOs and DSOs needs to be, and determining how much connectivity is required to enable each framework.

Over the next year, EPRI will update its bulk market and DSO operational modules to integrate and manage DER aggregations. "We are going to upgrade our existing ISO and DSO tools to include DER management capability," Renjit said. "This helps us study the benefits and limitations of different TSO-DSO coordination frameworks when DERs provide grid services. By the end of next year, we will have some interesting resources to share."

## EPRI TECHNICAL EXPERT

Ajit Renjit



# Achieving the Promise of Digital Transformation

*A new EPRI initiative seeks to leverage the power of data and technology to support utilities as they navigate the energy transition*

***By Chris Warren***

When the COVID-19 pandemic first triggered lockdowns in the spring of 2020, businesses in virtually all industries faced a dilemma: how to continue operating and engaging with customers when face-to-face interactions were impossible. For many companies, the answer was to initiate or redouble efforts to implement digital tools that allowed internal operations and collaboration to continue in a virtual world and, importantly, made it easy for customers to purchase goods and services online.

There are endless examples of how this played out. Faced with branch closures, for instance, banks made huge digital investments to allow customers to communicate with them on the digital channel of their choice and to perform transactions online. The need to quickly adapt to the pandemic dramatically accelerated the digital transformation already underway across the economy. In fact, a survey by McKinsey & Company at the end of 2020 found that the pandemic sped up the digitization of internal operations and customer and supply chain interactions by three to four years.

## THE UTILITY INDUSTRY'S SHIFT TO DIGITAL

Though not moving as rapidly, the utility industry is in the midst of its own digital transformation. A host of factors is spurring this transformation in addition to the pandemic. For instance, as large numbers of experienced utility employees near retirement, developing digital tools that institutionalize their knowledge and make it accessible to new workers becomes increasingly important. The proliferation of sensors and analytics capabilities such as machine learning algorithms also offers the opportunity to monitor the health of equipment in real-time and perform maintenance to prevent potential outages.

For over two decades, EPRI has collaborated with members, technology providers, and other stakeholders to research and test digital technologies with the potential to bolster worker effectiveness, improve asset monitoring, and provide greater clarity when making investment and operational decisions. Early work included the development of the Utility Communications Architecture in 1999 and the IntelliGrid Architecture Framework in 2005; both of these emphasized power delivery. Nuclear plant modernization, which has a significant digital focus, has been a dedicated research and development area since 2019. In 2017, EPRI launched the I4GEN Working Group for non-nuclear generation assets. I4GEN stands for Insight through the Integration of Information for Intelligent Generation.

As the name indicates, I4GEN's efforts have been focused on leveraging advances in big data, artificial intelligence, and the Internet of Things to make power generation more flexible, cost-effective, and resilient. One example of I4GEN's research is in the realm of advanced pattern recognition (APR) software to improve the monitoring of plant equipment. In the past, employees manually collected data from plant components. APR, by contrast, provides near-continuous collection and analysis of component data about everything from pressure and temperature to vibration and other parameters. This steady stream of data and analysis can surface trends indicating potential failures that can be prevented with proactive maintenance.

## A MORE HOLISTIC APPROACH TO DIGITAL TRANSFORMATION

The development and implementation of digital tools across all aspects of the utility industry have led to a broadening of EPRI's research and collaboration. While numerous digital transformation efforts such as I4GEN continue, EPRI's cross-sector collaborative work in support of digital transformation seeks to connect the parallel sector-specific efforts to better support the overall shift towards a more distributed, decarbonized, and flexible power system.

"We are poised to do work under the umbrella of digital transformation to support the energy transformation as well as utilities facing practical challenges today," said Susan Maley, an EPRI technical executive spearheading the effort. "A lot of our programs are working on technologies that contribute to a digital solution; we are trying to integrate those technologies systematically to advance the goals of our members."

The benefits and applications of digital technologies can take many forms and depend very much on the priorities, existing systems, expertise, and business models of utilities. However, there are shared concepts that can help guide utilities in leveraging digital transformation to benefit their operations and their customers. A digital transformation framework has been a focus of EPRI's work in 2022.

"This is a cross-sector effort. And from that, we will develop a set of common themes and a digital transformation maturity model that members can use to develop strategies and measure their progress," Maley said. The themes and model are currently being developed and will seek to address several common challenges around digital tools and the data needed to make them valuable.

## A COMMON DIGITAL TRANSFORMATION RESOURCE PLATFORM

A big challenge is bridging the gap between developing promising individual digital tools and utilizing them in a way that allows utilities to make tangibly better decisions. "There are EPRI staffers who have done phenomenal work developing tools, like a digital twin or advanced analysis tools," Maley said. This is an important and necessary innovation. One goal of digital transformation is to transition these tools and algorithms to utilities to provide near-term tangible benefits.

"Our aim with digital transformation is to operationalize or institutionalize a suite of integrated technologies that provide for near-term benefits and fit within an overall digital strategy for an individual organization," Maley said. "The digital tools and integrated technologies should enable a utility to make more informed decisions, acting in a more timely manner or with a better appreciation of the risks involved. They can also help to overcome a deficit in experience." The digital transformation framework and maturity model support this overarching approach and transformation journey.

Although digital transformation will have different objectives and tools in the nuclear sector compared to, say, power delivery and utilization, there are some common themes and challenges across sectors. One instance involves data management and infrastructure. "The IT pieces of this are critical and are common," Maley said. "The data infrastructure is agnostic about whether you're trying to send electrons along a wire generated with nuclear or renewable power. It's all data that has to be managed, analyzed, and used to make decisions."

One of the challenges EPRI and others are addressing is how to overcome the fact that beneficial data often sits in multiple databases and software; this is what "siloed" data means. Making use of that data means extracting it, cleaning it, staging it, and making it available for analysis. One of the goals of digital transformation is to move from manual data management to automated data management. "What does the combination of digital transformation resources look like to integrate these systems?" Maley said.

Data management is also a talent issue that will likely remain a challenge if it isn't addressed. For instance, utility employees with decades of experience may spend much of their time manually entering data instead of maintaining equipment or making planning decisions. "Their expertise is needed in the field or plants around operating and maintaining assets. These positions are hands-on, fast-paced, critical thinking, experience-based, and require timely decisions to be made," Maley said. "But they may be spending a significant amount of their time on data entry."

The work developing common themes and a digital maturity model is ongoing and will draw on EPRI's cross-sector expertise. Ultimately, though, these and other tools and resources will support a fairly straightforward outcome: to use technologies and data to make better decisions.

Utilities have significant decisions ahead of them with regard to the ongoing energy transformation, which is intended to greatly expand electrification and dramatically reduce carbon emissions. By 2030 and 2050, power and electricity generation and delivery are envisioned to be very different than they are today. "How we manage the assets, empower the people in our industry, and optimize our systems will be largely based on data and information," Maley said. "The digital transformation will be an important contributor to well-informed, timely decision making."

## EPRI TECHNICAL EXPERT

Susan Maley

**About EPRI**

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, affordable, and equitable access to electricity across the globe.

Together, we are shaping the future of energy.



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