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MAKING DISTRIBUTION GRIDS STRONGER, MORE RESILIENT

ALSO IN THIS ISSUE:

The Future of Generation: Intelligent, Integrated

ISO: A Multifaceted Strategy to Integrate Solar in California

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Viewpoint—Smart Ways to Make a Stronger Grid

Discussions among policy and electricity sector leaders in recent years have at times included the question of whether we should pursue a smart grid or a strong grid. For example, Kennedy Maize wrote in *Power Magazine* in 2013 that he preferred "strong grid" to "smart grid"—emphasizing such aspects as grid resilience and grid hardening. As a simple either-or proposition, the implications would be significant for utilities' strategic plans and capital budgets. As a practical and strategic consideration, many of us see the need to emphasize both.

For everyone engaged in research and development, such questions are important. They get to the heart of our research portfolios, which require thinking that is both comprehensive and focused on very particular aspects of power production, delivery, and use.

Looking at just four of the articles in the July-August *EPRI Journal*, we can examine the question of "smart or strong" in light of EPRI research.

Make Components and Infrastructure Stronger

One *EPRI Journal* story begins from the perspective of Central Hudson Gas & Electric in New York, which in one three-year period was struck by the four worst storms in its history. While the utility's customers and the broader public could acknowledge the magnitude of the challenge, they also looked to the utility to strengthen the grid—and particularly those aspects related to hardening and resilience.

If you like traditional "let's-break-it-so-we-can-make-it-stronger" research, you'll enjoy reading about how we dropped "trees" on power lines with just that goal in mind. Our work has shown that there are incremental but effective improvements that we can make to the familiar poles-and-wires infrastructure to make the power system stronger and more resilient.

The Promise of New Materials

Power plants typically ride out storms in good shape, but a more demanding power system is driving us to search for materials that can withstand higher temperatures and pressure. As variable renewables claim a larger share of power production, many thermal plants will need to ramp their production up and down to balance production, resulting in significant thermal and other stresses on plant materials. Also, we project that a coal-fired plant operating at 1400°F could deliver a 20% emissions reduction and a 24% increase in thermal efficiency relative to the average of today's U.S. coal fleet. In a world in which policy and technology drive us to reduce emissions for the long-term, old power plants and old materials must give way to the new.

EPRI Journal reports on our participation in the Advanced Plant Component Test Facility, which will retrofit a coal-fired facility with nickel alloy components and then operate it at 1400°F for two years. Researchers expect to learn a great deal by putting components through 2,000 thermal cycles.

The Importance of Smart and Strategy

Mark Rothleder's interview can help us put a smarter-stronger grid in perspective. As the California Independent System Operator's vice president of market quality and renewable integration, he has significant responsibilities for addressing that state's integration of solar resources.

He describes rapid supply swings of 1,000 to 1,500 megawatts, predicting such swings will increase in frequency and magnitude. He points to the need for active power control of solar resources, citing a 7,000-megawatt production ramp when the sun rises. System operators will require comprehensive monitoring and control for a grid with more distributed, dynamic resources.

This illustrates the need to develop a strong grid by making a smart grid. Along with that, Rothleder points to what I describe as "strategic strength," built on a principle that EPRI's research has demonstrated for more than a decade: We need the full portfolio of resources. Among others, he describes the roles of efficiency, storage, demand response, and smart inverters.

And if we can align retail rates, market design, and grid resources, we can optimize the grid using much more diverse resources.

Strength from the Customer

To align the power system, its markets, and rates, we must understand first what the customer wants or prefers. EPRI surveyed customers served by Kansas City Power & Light, Salt River Project, and 12 local power companies served by Tennessee Valley Authority (TVA). We looked at rate plans, pricing, and contract length, among other things.

We learned that about a third of the utilities' residential customers prefer time-of-use pricing over a flat rate. We are considering additional surveys to look at service plans and grid-interactive devices such as smart thermostats and water heaters, and researchers are conducting a discrete choice experiment to evaluate customer preferences for rooftop photovoltaics and community solar programs.

From the customer's perspective, much of our research is out of sight and out of mind. But the grid's fundamental strength and the value of our research and development ultimately will be measured by the customer's comfort, convenience, choices, and satisfaction with the products and services provided by the grid and its electricity.

From EPRI's perspective, the customers' needs are never out of sight or mind. Given the emergence of a power system operating with much more dynamic, distributed, and digital systems and components, we see "smart" as essential to "strong." And we are committed to strength as fundamental to every part and aspect of the system.

Mike Howard

President and Chief Executive Officer, EPRI

Making Distribution Grids Stronger, More Resilient

Three-Year Research Project Looks at Pole-Top Components, Vegetation Management, and More

By Phil Zahodiakin

Electric utilities have sharpened their focus on resiliency following widespread outages from an unprecedented series of superstorms including Hurricanes Katrina, Rita, and Sandy and the Halloween Nor'easter of 2011.

"Those and other storms brought a focus on aging infrastructure and what we could do to prevent widespread outages," said Chuck Talley, manager of Distribution Engineering Services at American Electric Power (AEP).

In 2015, EPRI concluded its three-year Distribution Grid Resiliency Project with 27 utilities, which evaluated options for strengthening electric distribution systems and provided a solid foundation for future research while informing utility investment to improve resiliency.

Holding Utilities to a Higher Standard

The superstorm outages made clear that society as a whole had grown profoundly more dependent on the Internet, Wi-Fi, and smart phones. "We've seen a major change in residential customers' expectations of electricity providers," said Heather Adams, director of Electric Distribution and Standards for New York–based Central Hudson Gas & Electric.

"In just a three-year period, we experienced the four worst storms in our company's history in terms of customers impacted," said Adams. "Our customers and the media were judging our response to those storms much more critically than they would have 30 years ago."

"Utilities and regulators are very attentive to reliability scores such as SAIDI, but those are misleading metrics because they often exclude data on prolonged outages," said Mark McGranaghan, EPRI vice president for distribution and energy utilization. "Now utilities are expanding resiliency investments to address longer-term weather events."

Where the Research Focused

EPRI and participating utilities focused on current resiliency practices and improvements with respect to overhead structures, vegetation management, undergrounding, grid modernization, and storm response practices.

"When we framed the initiative, we kept the definition of 'resiliency' broad," said EPRI Technical Executive John Tripolitis. "Our focus was grid performance in severe weather conditions."

According to EPRI's McGranaghan, overhead structures and vegetation management are priorities for resiliency enhancements.

Overhead Structures: Traditional Approaches and New Technologies

In field tests, researchers intentionally toppled trees across decommissioned power line spans volunteered by PPL Electric Utilities, Xcel Energy, and AEP. They observed that damage occurred at weak spots many spans away—such as cracks in crossarms and poles, and corrosion in conductors—confirming the importance of inspection and maintenance.

EPRI also conducted stress tests on utility poles and overhead components at its Lenox, Massachusetts laboratory.

Findings from field and laboratory tests include:

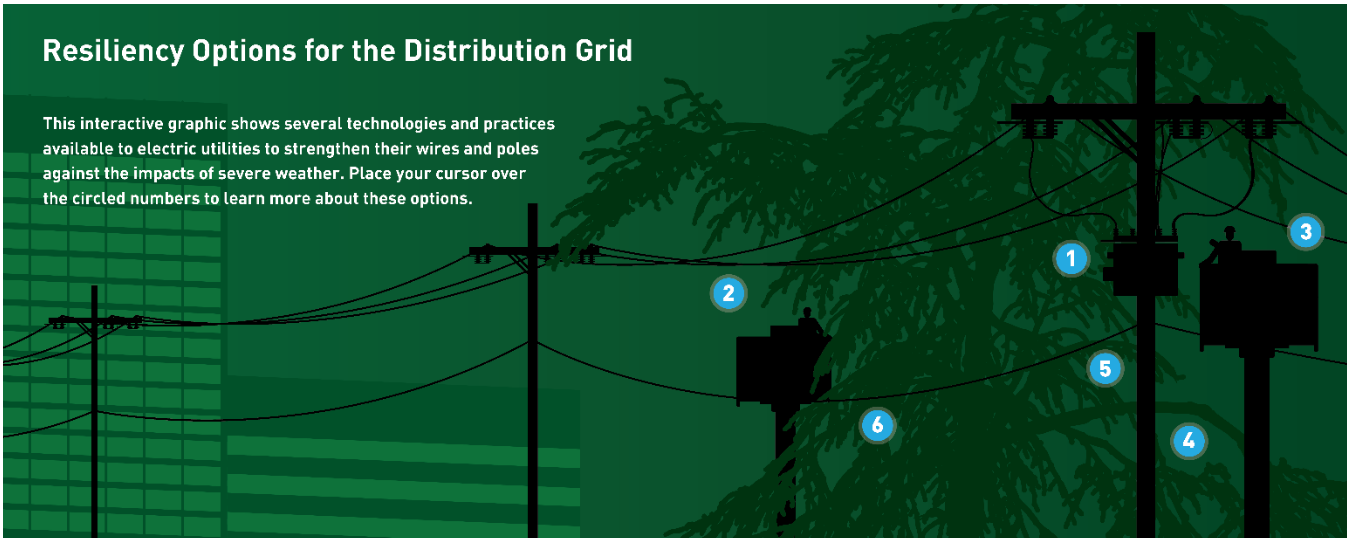
- When upgrading wooden poles, choosing replacements with a greater pole-top circumference may be more cost-effective than replacing them with steel or fiberglass poles. Pole-top strength is more important than base strength.
- When upgrading poles that carry automated switches, reclosers, and other critical components, it may be cost-effective to also upgrade adjacent poles, which can help absorb forces from tree impacts.
- Spacer cables can potentially reduce tree impact–related outages.

According to Tripolitis, collaborative research efforts into hardening overhead structures should continue to focus on open questions related to traditional resiliency approaches. These include data gaps regarding predictions for spacer cable performance as well as benefits of replacing wooden crossarms with stronger fiberglass versions.

"Our standards engineers are especially interested in the EPRI project data on fiberglass crossarms," said Central Hudson's Adams. "We currently apply wooden crossarms except in places where they have to withstand the greatest tension. When a tree hits the distribution line or pole, the impact forces must be absorbed somewhere. If they can't be absorbed sufficiently, the weakest component will break. This may be the pole top, for example, which would require a more complex, lengthy repair than a crossarm. These are some of the scenarios we'll be considering as we comb through the research results."

Researchers looked at designing weak spots into the system to minimize damage. For example, conductor ties can enable conductors to slip through when they are struck by trees, reducing the forces on poles and pole-top components. According to EPRI Senior Technical Executive Tom Short, these devices have not yet been proven in the field. "We haven't figured out the optimal slip resistance to prevent conductors from slipping out of their insulators many spans away," he said.

Also under investigation were "breakaway" conductors designed to break when trees fall on them, potentially protecting poles from damage and enabling easy repairs. As with ties, Short said that more field work is needed to validate the performance of these devices.



The interactive graphic shows several technologies and practices available to electric utilities to strengthen their wires and poles against the impacts of severe weather.

Vegetation Management: From Tree-Trimming to LIDAR

Tripolitis points to vegetation management as critical. Falling trees and branches are usually the leading cause of damage in severe weather. Because such programs are costly, utilities must weigh carefully their benefits relative to other resiliency investments. As part of EPRI's resiliency project, participants identified the industry's best vegetation management practices.

"Traditional vegetation management programs are designed to deliver reliability in normal weather," said Tripolitis. "But in severe weather you have trees falling into power lines from outside cleared corridors. So, we looked at tree trimming that can help prevent excessive damage during severe storms."

Particularly valuable is trimming above conductors so that fewer branches fall on them, preventing faults and outages. Other helpful practices include using the following:

- Geographic information systems to record pole locations, trim dates, trees targeted for removal, property boundaries, and more
- Sonic scanning to determine which trees are most likely to collapse in a storm
- LIDAR to measure the height of tree canopies to assess risks of trees falling into power line corridors

Going Underground

Underground circuits often are built in densely populated areas for increased reliability, safety, and aesthetic considerations. Elsewhere, underground lines support reliable electricity service to hospitals, airports, and other critical facilities during severe weather.

In major storms, underground distribution lines are far less susceptible to damage than overhead distribution. Outages can result, however, if the circuit's substation is knocked out or if underground equipment is damaged.

Utilities must evaluate many factors when considering burying lines. Are corridors for overhead lines prone to floods? Are hospitals and airports served by redundant circuits? How long can such facilities function with backup generators?

When examining the costs of various types of undergrounding projects, EPRI found that they vary widely among utilities and can be three to four times higher than those of overhead systems of equal length. Researchers also examined historical performance of various underground distribution systems in storms to identify cost-effective applications.

Grid Modernization

For grid modernization, research participants examined traditional approaches such as hardening poles and installing automated switches, along with emerging technologies such as sensors that indicate when poles and lines are down.

They concluded that the use of steel poles—even in areas with frequent severe weather—is not necessarily worth the investment. "We learned that Florida had a surprising number of steel poles fail during some big hurricanes in the early 2000s," said EPRI's Short.

Replacing wood poles with larger wood poles may or may not be a good option because "the survival of wood poles in severe weather seems to depend on the strength of the pole's overhead components," he added.

Advanced metering infrastructure offers promise for detecting outages and restoration. When service to a meter is interrupted, "it sends out a 'last gasp,'" said AEP's Talley. "So, depending on a utility's outage management software, those pings could be interpreted as a possible outage."

Possible, but not definite: EPRI concluded that outage-and-restoration detection with meters is not yet well-supported by field experience.

Utilities are deploying automated switches, which have been proven to work effectively under normal grid operating conditions. But in severe weather their reliability is questionable because they may not operate if their circuits are de-energized or their control system batteries have failed. Moreover, during a major event, the switches' communications with central operations centers could fail if the systems were overloaded. EPRI recommends additional research, particularly on more effective batteries for the switch controls.

Storm Response

EPRI and the utility participants compiled large data sets on the industry's many approaches to emergency planning, drills and training, weather forecasting, damage assessment, incident management, personnel strategies, and communications with customers.

Conclusions and recommendations include:

- In major storms, decentralize responsibilities for power restoration to those utility regional operations centers near outages to ease the burden on the main operations center and to more effectively manage restoration activities.
- In the largest weather events, utility personnel who don't routinely perform restoration duties may be called upon to serve. As a result, it is important to develop, document, and implement procedures (and related training) for key restoration activities such as addressing fallen conductors.
- Communicate estimated restoration times to customers after completing an initial damage assessment, and update customers with more granular estimates as restoration progresses.

In a separate project, EPRI is researching storm damage assessment with unmanned aircraft systems. The Federal Aviation Administration is developing regulations that will make it easier for utilities to deploy these systems for storm response.

Prioritizing Resiliency Dollars

Participants in EPRI's project developed a model to help utilities prioritize resiliency investments, building on a method developed by AEP. AEP's Talley said that the project "elevated our tool to beta 2.0" by incorporating methods to score the benefits of potential investments.

"For each distribution circuit, you input customer profiles and circuit characteristics, such as vegetation density, performance data, and the circuit's age," said Talley. "Then you input resiliency options, and the tool gives you cost-benefit scores. Currently, the tool must be run by individual circuit. If you have 6,000 circuits, you would run the tool 6,000 times. What's coming next is the ability to run it for groups of circuits and to drill down into sections of very long circuits."

Transferring Results from the Field

The next step for utility participants is to apply the project's findings and recommendations to resiliency efforts in their service territories.

"One of the greatest aspects of this project was the ability of our engineers to observe various concepts tested in a field scenario," said Central Hudson's Adams. "Seeing the concepts demonstrated on lines that replicate real distribution systems will help all our engineers to better apply the designs and conclusions from the project."

EPRI Tackles Electromagnetic Pulses

In 2016, EPRI launched research to help protect the U.S. transmission grid against electromagnetic pulses (EMP).

Part of EPRI's Transmission Grid Resiliency project, this EMP research will evaluate grid vulnerabilities and the costs and benefits of mitigation options.

"Industry participation in the research has been tremendous and is growing every day," said Rob Manning, EPRI's vice president of transmission research. "The issue is getting more attention in government circles because of the potential impact of an electromagnetic pulse on the entire power grid."

The Transmission Grid Resiliency project is looking at other threats as well. For instance, with the North American Electric Reliability Corporation, EPRI has developed tools to assess the potential impacts of geomagnetic disturbances. EPRI also recently completed a guide to help power companies assess severe weather threats.

EPRI Examines Metrics and Cost-Benefit Frameworks for Climate Resiliency

Recent extreme weather and natural disasters are heightening vulnerabilities of electricity infrastructure and operations. Drought, heat waves, hurricanes, wildfires, flooding, and severe winter storms have resulted in costly disruptions and damage to power systems. Increasingly, strategies to address climate change are focused not only on greenhouse gas mitigation but also climate resilience. For example, the U.S. Climate Action Plan of 2013 emphasizes climate preparedness and resiliency alongside domestic carbon reductions and international climate action.

To enhance climate resilience, electric utilities can assess vulnerable infrastructure, evaluate risks, and identify opportunities to harden assets and operations. To prioritize among investment options and support recovery of costs, utilities are often required by regulators to demonstrate that projects would yield net benefits for their customers. However, without metrics specific to resilience, the benefits of resiliency measures are being estimated with metrics traditionally used for reliability planning.

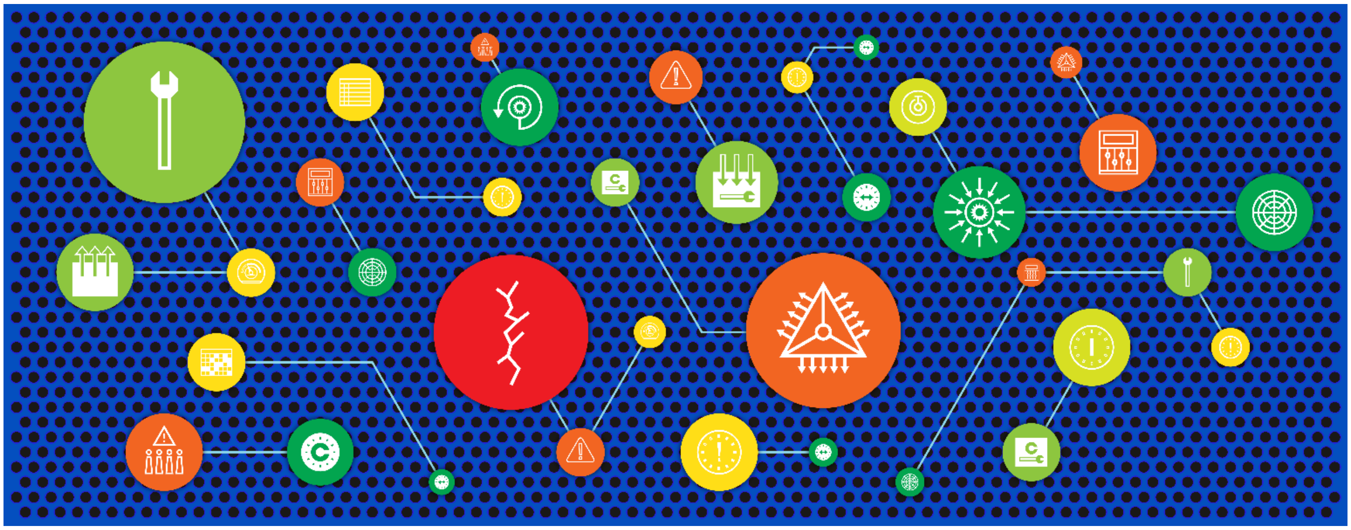
"While there are commonalities between resiliency and reliability, there are critical differences related to the type of hazards and their 'low-probability, high-consequence' nature," said EPRI Senior Technical Leader Delavane Diaz. "As a result, reliability metrics such as average service interruption indices and outage cost estimates are not well-suited for characterizing resilience."

To address this gap, EPRI is conducting a technical assessment of resiliency metrics and analytical frameworks and facilitating a collaborative forum for electric companies to discuss the merits and limitations of those approaches.

Key EPRI Technical Experts

John Tripolitis, Matt Olearczyk, Tom Short

The Future of Generation: Intelligent, Integrated



EPRI Outlines Framework for Comprehensive Digital Power Plant Operations

By Brent Barker

It's early morning on what's expected to be a hot, humid day in June 2025, and operators at the Smithson Power Plant receive a dispatch request along with input from the company's fleet operations. The 12-hour wind forecast has just been revised downward, and unexpected cloud cover is moving across the region. With wind and solar output falling, Smithson's two coal units are being dispatched to meet afternoon peak demand. One, a supercritical unit, will remain in baseload operation with a modest output increase. The other—a unit refurbished five years earlier to ramp up production more quickly and to cycle production more frequently—is asked to ramp up much faster than expected to meet the air-conditioning load.

Smithson's optimization algorithms sort through thousands of tradeoffs. There are economic consequences as a result of an outage or increased maintenance costs on a 20-year old plant.

Workers with handheld computers listen and interact with the machinery, sending word to the Advanced Process Control Network to fine-tune the fuel/air mixture. Meanwhile, the Advanced Monitoring and Diagnostics Network has recognized precursors of a fault signature in the turbine thrust bearings and a potential problem in a boiler tube, likely due to creep and fatigue from the thermal stresses of daily cycling. It alerts the Advanced Operations and Maintenance (O&M) Network, which moves up a scheduled outage so that the bearings can be replaced and the boiler tube repaired.

The Optimization Central Network, which has been processing the various tradeoffs from the algorithms, suggests three feasible pathways. One: ramp up plant production slowly to 50% capacity, preventing temperature excursions that could further degrade the weakened boiler tube, but at the cost of reduced power production. Two: a steeper ramp to 75% capacity with a risk of further boiler tube degradation and still at lower production. And three: ramp up plant output swiftly to full capacity to meet the demand—but with a 16% chance of boiler tube failure. Optimization algorithms distill and portray the scenarios in simple 3-D displays for Smithson's operators, who opt for the middle course. They relay their decision to the fleet dispatch coordinators.

This is a glimpse of how integrated, intelligent generation may someday operate, driven by diverse energy resources, the growing need for flexible operations, and a digitally equipped workforce. Ultimately researchers see the likely need to integrate plants and fleets with a much more dynamic, interconnected grid.

“The mission profile of the fossil plant is changing,” said Tom Alley, vice president of EPRI’s Generation sector. “In the future, we may have plants called into service in the morning and shut down in the afternoon. Coal plants designed to operate 365 days per year may operate 30 days in the winter and 30 days in the summer. Workers may have to move from site to site, from one type of plant to another, requiring broader skills and greater versatility. The fossil fleet will have to shoulder much of the system flexibility.”

EPRI Principal Project Manager Susan Maley offers this analogy: “Large-scale central power plants are built like semi-trailer trucks, but may be driven like a race car in a world of more flexible operations and an ever-changing dispatch landscape. They will need a set of interconnected digital networks along with actionable information to operate this way while remaining reliable and safe.”

Managing Big Data

Power plant operations can shift their mission by incorporating new capabilities in digital technology. “In 10 to 20 years, operations will look like your smart phone,” said Maley. “Everything you need at your fingertips, uniquely configured the way you want to meet your objectives.”

Maley anticipates at least a tenfold increase in the use of advanced sensors to monitor as many plant components and processes as possible, from the coal piles to the turbine and generator to the switchyard. “These sensors will in turn create an exponential increase in real-time data—a data storm—that will have to be managed and processed,” she said. Algorithms can be embedded on site servers or “clouds” that work behind the scenes to make sense of the “big data,” enabling operators to focus on key decisions about operations and critical assets.

How is this possible? “Computing with large data storage and management is now cheap,” she said, “You can rent storage from Amazon.”

Maley and EPRI Director of Generation Fossil O&M Neva Espinoza are spearheading the “I4GEN” initiative to help power companies achieve comprehensive digital power plant operations. I4GEN—short for “developing Insight through the Integration of Information for Intelligent Generation”—offers an approach for using digital tools and techniques and deploying key technologies.

“We are challenging member companies to chart a digital path forward for power generation, taking a collaborative R&D approach,” said Espinoza.

The I4GEN Framework

I4GEN focuses on three categories of enabling technologies—real-time information, distributed and adaptive intelligence, and action and response—along with six major digital/information networks (see bullets below). These networks will operate independently and in concert—similar to the interworking of the human nervous, circulatory, digestive, and other systems.

- **Sensors and actuation**: streams real-time data on all aspects of the plant—process, performance, operating conditions, equipment conditions, and actuators.
- **Data integration and information management**: processes the flood of data, converts it to actionable information, and provides the right information to the right person at the right time.
- **Advanced process control**: fine-tunes chemical, thermodynamic, mechanical, and electrical process variables, such as fuel/air mixture, combustion temperature, and steam pressure.

- **Asset monitoring and diagnostics**: tracks material and equipment degradation, identifies fault signatures, and estimates the remaining life of components.
- **Advanced O&M**: uses diagnoses of equipment degradation and faults to implement efficient O&M practices. This network initiates actions because they're needed rather than because they are common practices at set intervals.
- **Optimization**: pinpoints the least-cost path to safety, availability, and reliability.

Simulation and the Virtual Power Plant

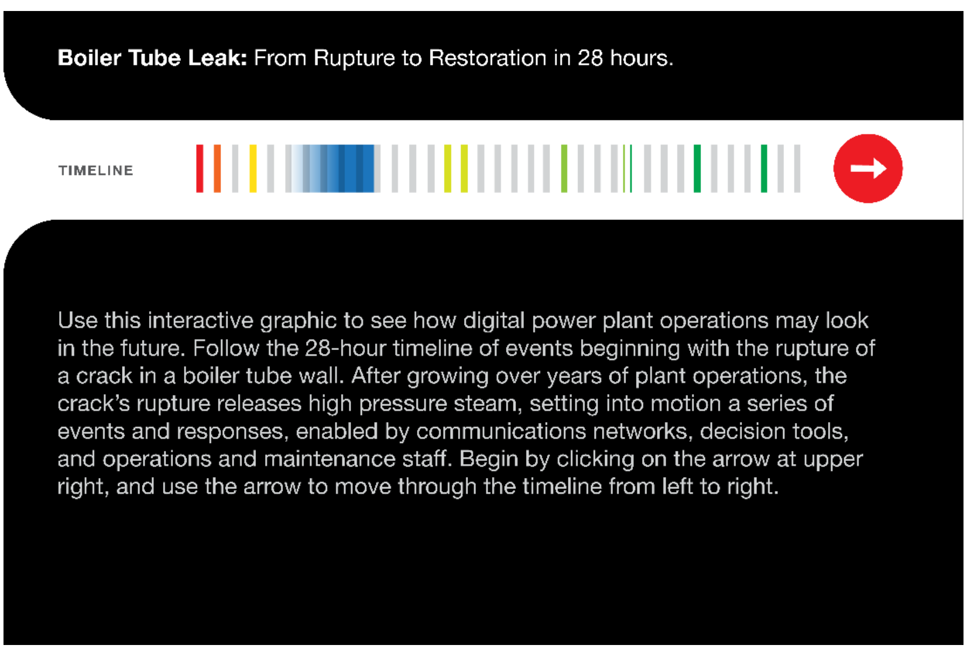
By processing a flood of real-time data, power plant simulation moves closer to reality. "Now a plant can have its own comprehensive digital, or virtual, 'twin' running by its side in near-real-time," said Maley.

The simulation doesn't control the plant directly. Instead, it integrates experience, history, and current and forecast conditions to provide the operator with a remote platform for learning, exploration, and decision making. "It's the same rationale and similar computational approaches as those for a driverless car," said Maley.

Virtual plants will be supported by algorithms that respond to changing grid conditions such as the need to ramp up power or stand by in reserve. Other algorithms will balance multiple objectives (such as enhancing safety, minimizing costs, protecting equipment, and maintaining emission levels within limits) and address shifting priorities (such as sending operators to cold-start a nearby gas turbine to meet an unanticipated surge in demand).

"If this were a car, your objective on day one might be to travel as efficiently as possible, conserving fuel," said Maley. "On day two, your objective might be to get to the same place as fast as possible."

While data transmission from plant sensors occurs in milliseconds, calculations required to optimize plant operations can take precious seconds to minutes. "Because of this time lag, optimization cannot always be automated," said Maley. "Instead, we are feeding experienced operators with distilled information, scenarios, and options to guide their decision making. Some of the toughest tradeoffs come down to financial risk/reward, and this is where operators are often better than computers. In the future, more actions could be automated so that staff have time to stay ahead of potential problems rather than react to them."



This interactive graphic depicts how digital power plant operations may look in the future.

I4GEN Next Steps

When introduced in 2015, I4GEN was well-received by EPRI's utility members. EPRI will consider advice from three member-led groups—the Operations and Maintenance Group, the Generation Council, and the Fleetwide Monitoring Interest Group—to help EPRI's efforts to refine and advance the initiative. Each utility can determine for itself to adopt various aspects and build a version aligned with its business strategy. One reasonable first step for a utility's consideration is to adopt elements with the highest return for a given plant.

"Most companies will not do a full retrofit. They will look for the most advantageous path," said Maley. "They might start with a digital backbone and then add sensing capability. That would lead them logically to invest in data management, storage, and security, followed by the adoption of advanced diagnostics and a control system upgrade. Each step paves the way for the next."

Investing in digitization will make financial sense for most new plants, but it may not result in sufficient returns for older plants, such as those retiring in the next 10 years. "The investment for digitally connecting assets is significantly less than the investment for upgrading major power plant components," said Maley. "We would like companies to consider the possibilities, devise a plan for their company or plant, and then move forward with the parts that make economic sense." She points out that companies such as Duke Energy, Southern Company, and Enel are taking similar, step-by-step approaches to digitization.

As with the smart phone, the key to successful power plant digitization is to separate the underlying complexity from user interfaces so that workers can focus on decisions and actions. "There are many talented data scientists now working on computational problems, so that we can concentrate on generating power," said Maley.

Key EPRI Technical Experts

Neva Espinoza, Susan Maley

First Person—ISO: A Multifaceted Strategy to Integrate Solar in California

The Story in Brief

Mark Rothleder is Vice President of Market Quality and Renewable Integration at the California Independent System Operator (ISO). In this interview with *EPRI Journal*, he discusses how solar is reshaping the California grid and how California ISO is integrating it into operations.

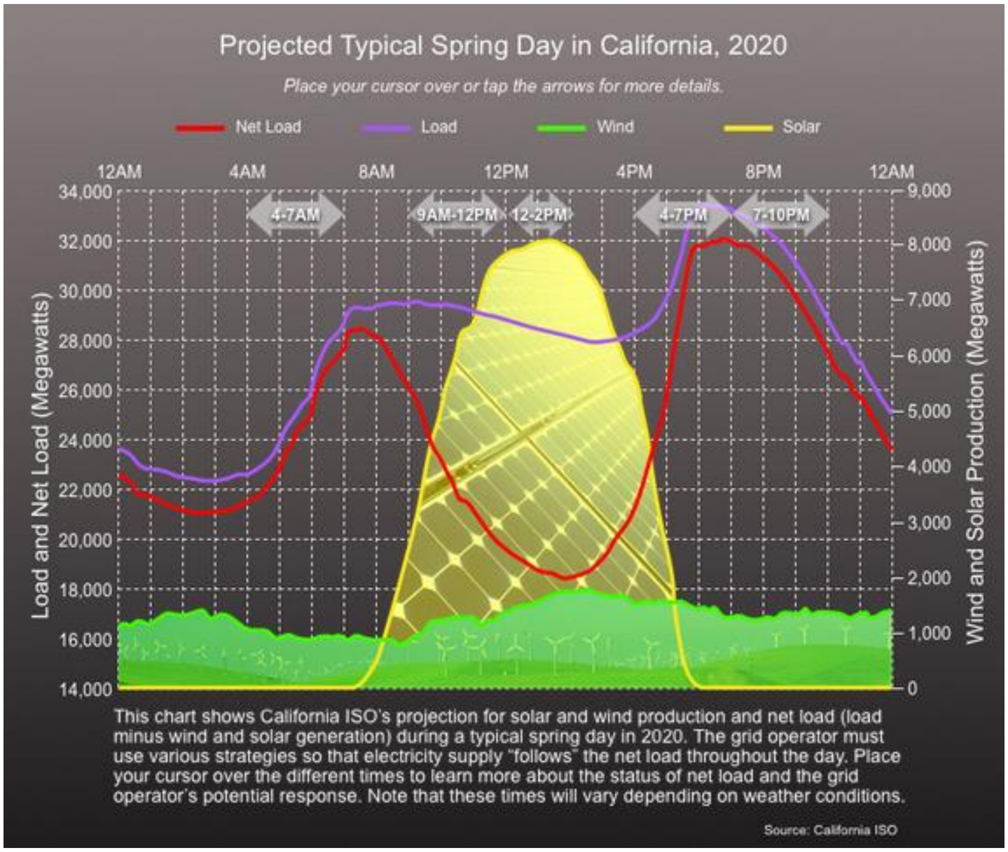
EJ: You're the longest serving employee at California ISO. What keeps you excited about grid operations work?

Rothleder: I'm employee number 4, starting in 1997. It's exciting how we're changing grid operations. In 1997, it was, 'How do we deregulate and have an open market?' Now the work has expanded to, 'How do we leverage that open market to integrate renewables and reduce the impact of greenhouse gases on the environment?' Over the long term, I'm excited about the continuing transformation to a low-carbon grid—and am looking forward to the opportunity to use renewable generation to enable other sectors such as transportation and buildings to reduce their carbon footprint. There are a lot of interesting things going on and many smart people working on them, and for me California ISO is the place to be.


Mark Rothleder

EJ: Describe how solar is reshaping the California grid.

Rothleder: With respect to "in-front-of-the-meter" solar connected to the transmission and distribution grids, we surpassed 7,500 megawatts of solar production during our last peak production period on March 31. For context, California ISO's installed electric generation capacity is about 72,000 megawatts. The ISO's peak load is about 50,000 megawatts. The California Energy Commission and Public Utilities Commission jointly report that about 4,100 megawatts of "behind-the-meter" solar is now installed. The transmission-connected solar has reduced our peak loads and played an important role filling in for reduced hydropower production over the last 3 or 4 years as a result of the drought.



EJ: What operational challenges have resulted from the influx of solar?

Rothleder: This year has been a more normal hydro year, and as we start getting mountain snow runoff, we're seeing more oversupply as a result of combined solar and hydro production when there is low demand. Managing oversupply is a challenge as we reduce output of other generation resources, including natural gas and coal to the extent possible. We can't turn every other resource off because we need some of them on for the evening load ramp as the sun goes down and people come home from work and turn on appliances.

A second challenge is that we are seeing a greater load ramp in three evening hours. Three and a half years ago, that ramp was about 6,000 megawatts. Now it's approaching 11,000 megawatts, and we'll be at 13,000 megawatts in a couple more years.

"In 1997, it was, 'How do we deregulate and have an open market?' Now the work has expanded to, 'How do we leverage that open market to integrate renewables and reduce the impact of greenhouse gases on the environment?"

EJ: Have you experienced any grid stability problems due to solar?

Rothleder: We haven't had stability problems, although on cloudy or partly cloudy days we're getting more supply swings in the range of 1,000 to 1,500 megawatts over 10- to 15-minute periods. Those swings are expected to increase in frequency and magnitude, so we will need to have enough operational flexibility to respond quickly and effectively. We do not typically activate our operating reserves for these swings.

EJ: What is California ISO's thinking about how to address these challenges?

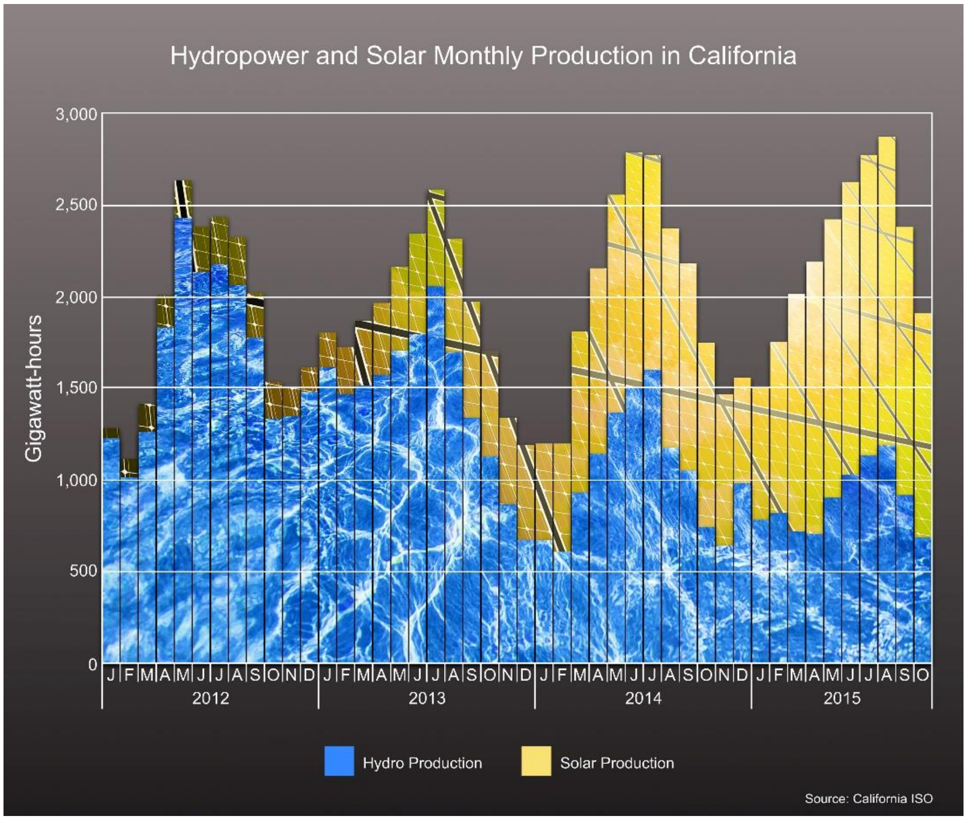
Rothleder: Our strategy is multifaceted. Energy efficiency can be helpful to bring down demand and reduce the evening ramp. Energy storage and advanced demand response are higher cost alternatives for now, but we believe as costs come down they will increasingly be part of the longer term solution to reduce solar generation curtailments. Solar and other renewable resources with smart inverters may provide grid reliability services such as frequency response, reducing the need to maintain other resources to provide such services. This does not require us to send any signals to the resources.

Aligning the retail rate structure and market design with today's grid resources is another important strategy. We need to send the right price signals, whether it's time-of-use rates or dynamic pricing. As we reach higher levels of renewables, we expect that regional coordination and diversifying the portfolio both geographically and technologically will be necessary parts of the solution.

EJ: How is California ISO forecasting solar generation right now, and what improvements are needed?

Rothleder: On the utility-connected side, a weather forecast company provides us with project-level solar forecasts. On the behind-the-meter distribution side, we work with a company that provides aggregate forecasts.

Many forecast experts track cloud movement, and that's good when there's gradual west-to-east movement across large solar fields. Where they fall short—and where research and development is needed—is thunderstorm cloud development over the fields. It's something that can happen rapidly and doesn't get adequately covered in cloud movement forecasts. Last summer, we experienced days when thunderstorm clouds developed over the solar fields in the southeast California desert, and we had some pretty big misses on our solar forecasts—off by as much as 4,000 megawatts between noon and 4:00 p.m. We're having discussions with forecast experts about developing new models to address this.



This chart of California hydro and solar production shows how solar helped to address the hydro shortfall as a result of the drought.

EJ: What are California ISO's plans with respect to operational control of solar resources?

Rothleder: For transmission-connected solar, we certainly want increased control. The newer solar projects enable the system operator to automatically dispatch the resources every five minutes, and that's been helpful. Short term, we'd like to get voltage support from solar resources, and we're involved in stakeholder efforts on the state, regional, and federal levels to develop interconnection rules to provide that capability.

Longer term, we will need active power control. When the sun rises, we get a 7,000-megawatt production ramp very quickly. If the solar doesn't have enough geographical diversity, there will come a point where the grid cannot accommodate so much, so fast—and active power controls can help manage that.

If we can get solar plants to be responsive to signals from us, we may be able to use them for frequency regulation as well. We have some demonstrations with new solar resources looking at this kind of control.

On the distribution side, we don't seek to directly control individual distributed solar resources. Instead, we're working with distributed energy resource aggregators on ways to manage these resources. Potentially, we could send signals to an aggregator requesting it to increase or decrease output.

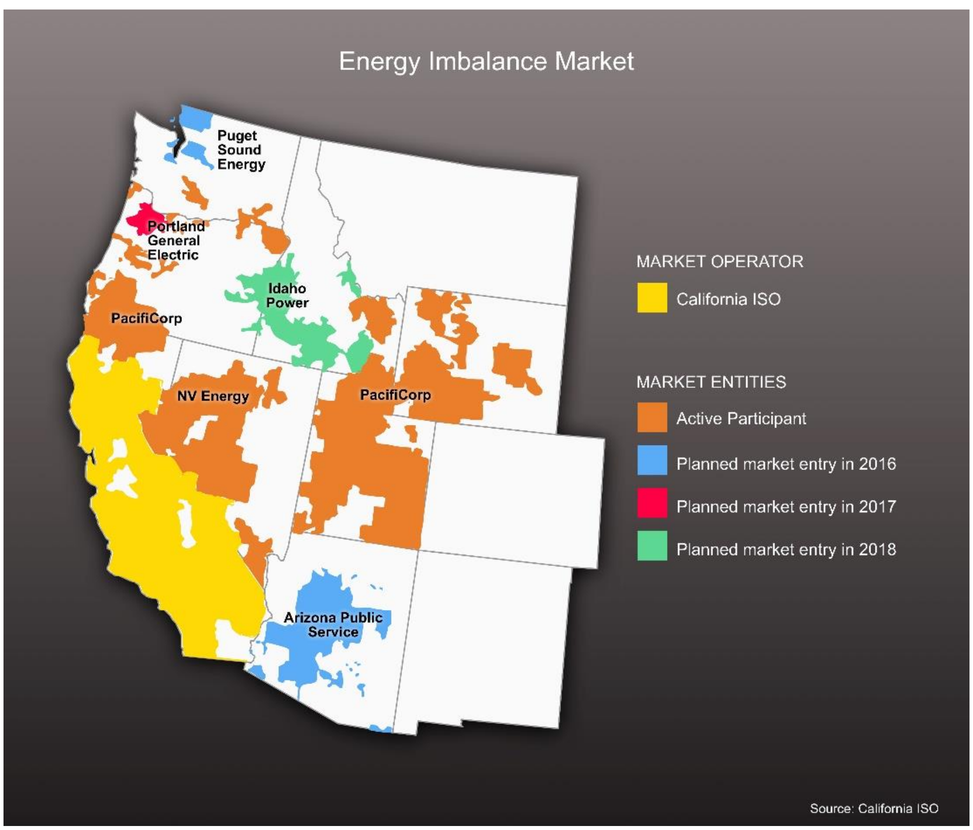
"As we reach higher levels of renewables, we expect that regional coordination and diversifying the portfolio both geographically and technologically will be necessary parts of the solution."

EJ: In November 2014, California ISO launched a regional coordination effort called the Energy Imbalance Market. How does the market work, and what have been the benefits and challenges?

Rothleder: The western Energy Imbalance Market is a real-time market that enables grid operators in six western states across different time zones to work together to balance last-minute energy supply and demand, which gives the participants more dispatch flexibility. For example, evening wind power in Wyoming can be used to help meet California's afternoon peak. We now have about 1,800 megawatts of economic transfer capability available in real time that was not available before. An algorithm determines the lowest cost resource to dispatch and transfer every 5 minutes and every 15 minutes to meet demand forecasts.

The market enables more efficient, cost-effective dispatches for the participants and often supports the full use of renewable energy. For example, when California has solar generation oversupply, we send the energy to our neighbors, which enables them to potentially reduce output of their non-renewable resources such as those fueled with natural gas or coal. That reduces the cost of curtailing renewable generation in California, and it saves our neighbors money because they're getting lower cost energy. Sharing flexible reserves has also reduced the participants' costs for maintaining those reserves. As of the last quarter, we're at about $64 million of benefits since the market launched.

With respect to the challenges, it's a paradigm shift for traditional balancing areas to have another market dispatch operating in parallel with their own operations. As we bring more balancing areas into the market, we will need more training on communications and information flow. For example, if an operator is ramping up a resource in response to a contingency event on the grid, he needs to inform the energy imbalance market and its automated dispatch about that action. Otherwise, the market may erroneously determine that it needs to respond to an energy shortfall.



EJ: What are the plans for the market's expansion?

Rothleder: Interest from other areas is expanding. Arizona Public Service and Puget Sound Energy are scheduled to begin participating in the Energy Imbalance Market this year. Portland General Electric will join next year, and Idaho Power announced its intent to join in 2018.

California Senate Bill 350, which passed last year, increases the state's renewables target from 33% to 50% by 2030 and authorizes the transformation of California ISO into a regional energy market—which expands upon the real-time balancing services provided by the Energy Imbalance Market to include more comprehensive services such as day-ahead grid optimization and long-term infrastructure planning. So we're working with stakeholders on a series of studies to examine how such a transformation would benefit California ratepayers, jobs, and disadvantaged communities, and how it would impact greenhouse gas emissions. Day-ahead planning would make the regional market even more efficient. If you can predict an oversupply a day in advance, the participants may not need to commit and transfer resources across markets.

> "When California has solar generation oversupply, we send the energy to our neighbors, which enables them to potentially reduce output of their non-renewable resources such as those fueled with natural gas or coal."

EJ: What are California ISO's needs for flexible generation capacity to help balance solar generation, and how are you pursuing them?

Rothleder: One way we're addressing the need is through our flexible ramping products. These are real-time and day-ahead energy products intended to manage generation resources so that we have enough operational flexibility, or resource options, in the right places at the right time. We use a flexible ramping algorithm that determines how much ramping capability in megawatts is needed for the next three 5-minute intervals and which resources can support that.

We're concerned about the possibility of not having enough flexible resources available as renewable generation increases and flexible resources are shut down or retired. We're quantifying how much ramping capability needs to be installed on the system to address the net load increase as a result of the reduction of solar production in the early evening. Last year, the California Public Utilities Commission put a mechanism in place for assessing flexible resource needs through its annual resource adequacy program. The commission has stated that a certain portion of our resource adequacy capacity needs to be dispatchable flexible resources. Currently, that portion is about 11,000 megawatts, but that is expected to increase.

EJ: What improvements are you working on with the flexible ramping products?

Rothleder: Currently, the ramping products enable procurement of up-ramping resources only. The next generation will have downward ramping capability to address energy oversupply. We're enhancing how we quantify ramping needs, over what period we need it, and how we allocate payments to energy resources.

EJ: California has a 1.3-gigawatt energy storage mandate. What function do you expect storage to serve in integrating solar and other renewables? What are the challenges?

Rothleder: The mandate helps to kick-start innovative storage applications. The longer term storage opportunities are in absorbing oversupply and providing frequency response.

The biggest challenge with large-scale storage is the high cost. Because grid-scale storage is such a large investment, a key question is how you share that investment among multiple entities that benefit from the projects. Small-scale battery projects don't suffer from that challenge.

EJ: What role do you expect demand response to play?

Rothleder: If you can couple demand response programs with the right price signals and time-of-use retail rates, you can potentially increase load at times when you want it—when electricity prices are low and you have an oversupply condition—and decrease load when you have too little supply or need to ramp up generation resources. I expect that such activities will be driven by large-scale industrial customers and demand response aggregators managing many smaller customers. Because demand response happens on the distribution system, it brings up the need for new coordination between distribution system operators and transmission system operators.

“Because grid-scale storage is such a large investment, a key question is how you share that investment among multiple entities that benefit from the projects.”

EJ: How can regulatory changes help?

Rothleder: Regulatory changes can help us make better use of energy resources, which strengthens grid efficiency and reliability. These include new solar interconnection requirements and regulations that enable solar resource aggregators to participate in the energy market.

EJ: What are the most important R&D needs for solar integration?

Rothleder: Solar forecasting is one. Another is how to optimize the grid operator’s control systems to make the best use of smart inverters. A third is how to use renewables for both upward and downward ramping so that they can provide reliability services such as voltage and frequency support.

EJ: What advice can you offer grid operators in other regions where solar penetration is still low but likely to grow?

Rothleder: We’ve been learning from their experience as well as sharing our experience using markets to integrate higher levels of renewables. Regarding advice, one is start preparing your system and your operations. Start thinking about whether you need additional flexible resources and how you will manage them to be responsive to variable solar generation. Collaborate with the renewable resource developers in your region so that they can be part of the solution.

Shaping the Future

Getting to Know the Customer

EPRI Tests a 'Discrete Choice' Approach to Examine Utility Customer Preferences

By Phil Zahodiakin

An EPRI study has demonstrated an approach for utilities to gauge their customers' interest in potential new electric services.

Traditionally, many U.S. residential utility customers paid flat rates for electricity. Now, distributed solar generation, energy storage, electric vehicles, smart thermostats, and energy management systems provide opportunities for utilities to consider offering more diverse service plans and rates.

Before utilities commit resources to new plans, they need to better understand customers' preferences. For example, would customers consider a time-of-use (TOU) plan or a fixed bill plan over a flat rate plan?

"It is important to engage with customers in thoughtful ways to find out what they want, because often new technologies and service options are brand new concepts for people," said Jen Robinson, a senior EPRI technical leader.

Developing a 'Discrete Choice' Survey

To examine customer preferences, EPRI adapted the research method known as a discrete choice experiment. "Discrete choice experiments are useful for estimating potential interest in new offerings with which customers may not yet be familiar," said Robinson. "An interesting example is the food company Prego, which used a related research approach to predict that a third of Americans wanted chunky spaghetti sauce before chunky spaghetti sauce even existed as a product."

Discrete choice experiment surveys introduce customers to a technology, plan, or product and then ask them to choose among hypothetical offerings with different combinations of features. The survey data are then used to estimate a "choice model" that evaluates customer preferences for the offerings.

"The resulting choice model also allows you to drill down to see what combinations of product features are likely the biggest drivers of customer preference," said Robinson.

EPRI developed the experiment and fielded surveys with three utilities: Kansas City Power & Light (Missouri), Salt River Project (Phoenix), and Tennessee Valley Authority (TVA). (For TVA, the survey queried customers from 12 of the local distributors of TVA power.) The survey asked customers about their preferences for TOU, fixed bill, and flat rate plans, along with specific plan features such as TOU peak and off-peak prices, length of the peak period, TOU seasons, and fixed bill contract lengths.

The surveys also asked customers for demographic information, enabling the choice model to differentiate the relative effects of plan features and demographics.

"Careful consideration of the questions is needed to develop a choice model that provides the most useful insights," said Robinson.

Prior to conducting the survey, researchers carefully tested and measured customers' understanding of the concepts and questions.

Different Regions, Similar Results

Researchers applied the choice model to each utility's service territory using demographic information from U.S. Census data, enabling the utilities to estimate potential market size for the new rate plans.

Although the surveys were completed by customers from different regions and served by different types of utilities, the model's application predicted similar results for each utility. For example, about a third of the utilities' residential customers prefer TOU pricing over a flat rate.

Using the same approach, EPRI is planning a second round of surveys on preferences for additional service plans, potentially including grid-interactive devices such as smart thermostats and water heaters that can be matched with various rate structures. Researchers are conducting a discrete choice experiment to evaluate customer preferences for rooftop photovoltaics and community solar programs. Another is in the works to examine preferences for electric vehicles.

Key EPRI Technical Experts

Jen Robinson

Innovation

Simulating Future Grid Reliability

New Framework to Link Separate Models and Capabilities

By Garrett Hering

Earlier this year, the Federal Energy Regulatory Commission (FERC) issued guidelines to help electric utilities, transmission operators, planning authorities, and other stakeholders better understand potential grid reliability impacts stemming from the U.S. Environmental Protection Agency's Clean Power Plan.

The guidelines encourage the creation of modeling tools and techniques to improve analysis of reliability related to "emerging and ongoing trends in the power industry." These include more:

- Variable renewable energy generation
- Reliance on natural gas
- Flexible operation of fossil-fueled and nuclear power plants

To address this, EPRI is developing and demonstrating an advanced modeling framework for use with existing simulation tools and methods to provide more rigorous reliability analysis. The framework will enable transfer of data among various tools covering different timescales so that they can be used to determine potential reliability impacts of diverse policies and industry trends. Ultimately the framework will be used by power system planners.

"With the grid adding extensive variable energy resources such as wind and solar, no comprehensive tool exists that equips researchers and resource planners to adequately assess reliability concerns," said EPRI Technical Executive Adam Diamant.

The framework initiative builds on EPRI's portfolio of production cost and generation capacity expansion modeling tools, including its Electric Generation Expansion Analysis System (EGEAS) software and U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model. It also supports EPRI's Integrated Grid work and research to identify modeling gaps to better understand power system changes.

Testing Today's Tools

EPRI began by reviewing today's commercially available and research-focused models. In one study, researchers used the National Renewable Energy Laboratory's FESTIV model to look at how new flexible ramping products can affect grid operations.

"FESTIV is helpful for studying flexible ramping products and other aspects of grid operations, but it's not able to capture all reliability impacts. We want to link these types of tools with other tools to get a fuller picture," said EPRI Project Manager Erik Ela.

Applied individually, FESTIV, US-REGEN, and other software tools can't model the full complexity of the changing power system and the impacts on reliability. Modelers need a greater ability to link inputs and results across various tools.

For example, researchers may be able to use US-REGEN to assess how a particular deployment of generation capacity will affect electricity prices, power company revenues, and emissions. But other tools, such as FESTIV, are needed to gauge whether that capacity has sufficient operational flexibility to maintain prescribed system frequency.

Making Tomorrow's Models

EPRI will investigate how to enable data flows among various models to identify and evaluate reliability concerns such as frequency response, voltage control, and operational flexibility.

With a final version slated for the end of 2017, EPRI plans to use the framework as the foundation for future research and will work with electric utilities to refine and test it on electric system operations.

Key EPRI Technical Experts

Erik Ela, Aidan Tuohy, John Bistline, Adam Diamant

In the Field

Integrating Megawatt-Scale Solar in Indiana and Michigan

EPRI, Indiana Michigan Power Company Examine Generation, Variability, Costs, Benefits, and More

By Chris Warren

It was an historic moment for the Indiana Michigan Power company (I&M) and its parent company American Electric Power (AEP). In December 2015, their first company owned-and-operated solar plant—a 2.5-megawatt facility near Marion, Indiana—began generating electricity. The milestone reflects the companies' recognition that solar power is becoming affordable and practical.

I&M is building three more solar plants, and its most recent integrated resource plan (while subject to change) proposes to increase solar generation by 4,000% over the next 20 years.

"We recently retired a large coal unit and the cost of solar has dropped, so our integrated resource plan indicated a solar power plant was becoming a more reasonable option," said Marc Lewis, I&M's vice president of regulatory and external affairs.

Given I&M's limited experience with solar—there are only about 100 net-metered residential installations connected to its distribution grid—the utility has many questions about the impacts and benefits of owning and operating megawatt-scale solar power plants. For instance, I&M wants to understand more clearly the performance of different panel technologies in Midwestern weather, best maintenance practices, and distribution grid impacts.

Gathering Data at Four New Plants

In 2015, EPRI and I&M launched an Integrated Grid pilot project to evaluate the performance and grid impacts of the Marion plant, along with three other utility-scale solar plants that will be connected to I&M's distribution grid by the end of 2016: a 4.6-megawatt facility in Michigan and 2.6-megawatt and 5-megawatt plants in Indiana. I&M will collect performance data for a year, and EPRI will analyze it.

"Solar output varies with temperature and irradiance," said EPRI Senior Project Engineer Steven Coley. "Based on each plant's particular location, design, and panel technology, we are modeling its expected generation and comparing that to actual generation." EPRI also will assess generation variability throughout the day and in different seasons and compare actual and predicted returns.

Distribution Grid Impacts

EPRI will examine the costs and benefits of connecting the plants to different parts of the distribution grid, including whether voltage regulation devices, capacitor banks, adjustments to protection equipment, and other upgrades are needed to maintain grid reliability and power quality at acceptable standards.

With respect to benefits, siting solar near large loads can reduce power line losses and avoid the need for expensive new equipment. "In some areas, you might not need to upgrade transformers if the solar output aligns with peak load and can be relied upon to reduce peak demand," said Coley.

The pilot project will help I&M build its solar expertise in several areas, such as:

- Impacts of weather conditions on solar generation in different parts of its service territory
- Generation from different solar panel technologies
- Solar energy delivery and its impact to the distribution grid

I&M can use this knowledge to reach the solar generation target in its integrated resource plan and assist large commercial and industrial customers that want to purchase solar electricity. “If there was a customer interested in having us build and operate solar to serve their needs, the lessons learned with this pilot will help us do that,” said Lewis.

Based on this benefit-cost analysis, along with the results of other Integrated Grid pilot projects, EPRI plans to publish findings and lessons to help utilities optimally integrate solar into power systems. These may include factors that utilities can consider in siting solar plants.

Key EPRI Technical Experts

Steven Coley

In the Field

Spent Nuclear Fuel Storage Demo Heats Up

Ten-Year Demonstration to Begin in 2017

By Garrett Hering

Storage of spent nuclear fuel in dry casks is widely considered low risk, based on decades of research and testing by EPRI and nuclear industry stakeholders. After three years of successful preparatory work, an EPRI-led demonstration to confirm the current understanding of extended spent-fuel storage is on track to begin next year.

Nearly all spent fuel pools at U.S. nuclear plants are approaching their capacity. Since 1986, dry casks—which can enable storage for decades if aging effects are properly managed—have been used to expand that capacity. As the nuclear industry generates more high-burnup spent fuel to improve reactor economics, more data is needed to support the fuel's long-term storage in casks. A rigorous cask demonstration is especially important given the recent cancellation of the permanent spent fuel repository at Yucca Mountain.

As part of a joint project between EPRI and the U.S. Department of Energy (DOE) launched in 2013, nuclear power researchers, scientists, operators, and technology vendors are creating a specially equipped commercial dry storage cask for high-burnup spent fuel. By 2017, the cask will be ready for a 10-year demonstration to study the behavior of the high-burnup spent fuel stored inside.

Lessons and data from the project will inform low-risk storage of spent fuel and the U.S. Nuclear Regulatory Commission's (NRC) licensing process for fuel storage. Project participants include utility Dominion Virginia Power; technology vendors AREVA, Westinghouse, and NAC International; and six DOE national laboratories.

Cask Design Completed, Sensors Installed

In 2016, researchers completed preparatory work critical for monitoring the cask, which in 2017 will be loaded with several types of high-burnup fuel using standard industry practice and then moved to the concrete pad at Dominion's North Anna nuclear plant in Virginia for storage.

"We completed the cask design document required for Dominion's storage licensing request to the NRC, and AREVA and Westinghouse extracted 'sister' rods from high-burnup assemblies at North Anna and shipped them to Oak Ridge National Laboratory," said EPRI Project Manager Keith Waldrop.

These sister fuel rods, currently stored at Oak Ridge, are similar to those that will be loaded inside the cask. Researchers will compare their physical state following about a decade of storage.

During the demonstration, researchers will measure internal temperature at different points in the cask using seven thermocouple lances equipped with multiple probes. The team will collect gas samples from the cask periodically for laboratory analysis. After the cask is completed later this year, it will be shipped to North Anna in February 2017 for loading in July, pending NRC's approval.

Photo courtesy of Dominion Virginia Power
Technicians at Dominion Virginia Power's North Anna nuclear plant prepare a shipping cask containing fuel rods from high burnup assemblies for shipment to Oak Ridge National Laboratory. These "sister rods" are similar to ones that will be loaded inside a specially equipped dry storage cask as part of an EPRI-led 10-year demonstration project.

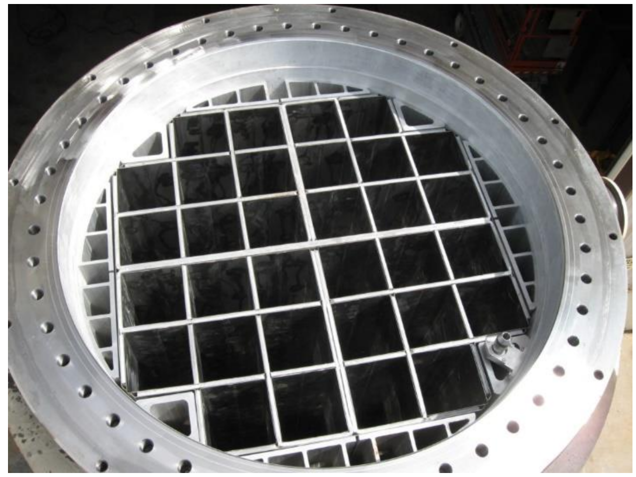


Photo courtesy of AREVA TN
View inside the commercial dry storage cask that EPRI is equipping with special instruments to measure the behavior of high burnup fuel.

Photo courtesy of Oak Ridge National Laboratory,
U.S. Department of Energy
The shipping cask with sister fuel rods after it arrived at Oak Ridge National Laboratory in early 2016. Researchers will compare the physical state of the sister rods and the rods inside a specially instrumented dry storage cask after a decade of storage.

Improving Safety and Licensing

Research data will be used to support high-burnup license applications and renewals. For instance, Xcel Energy will use project data to fulfill aging management conditions in its recently renewed license to store high-burnup spent fuel at its Prairie Island Nuclear Generating Station in Minnesota.

"We are all collaborating so that the public is confident that we can store high-burnup fuels in dry storage systems until a federal solution becomes available," said Terry Pickens, Director of Nuclear Regulatory Policy at Xcel Energy, who leads the project's industry review team. "Federal solutions could include relocating spent fuel to a consolidated interim storage site or permanent disposal in a deep geologic repository at Yucca Mountain or another acceptable site."

Researchers plan to evaluate the results of cask monitoring from 2017 to 2027 and ship the cask to an undetermined facility in 2027 for post-storage testing.

Key EPRI Technical Experts

Keith Waldrop

In Development

Turning Up the Heat

Ohio Facility to Test Advanced Coal Plant Components at 1400°F

By Chris Warren

Between 1920 and 1960, the average thermal efficiency of U.S. coal plants increased from about 5% to more than 30%. This impressive gain was driven largely by an increase in plant operating temperatures from about 600°F to 1100°F in the 1960s.

Since the 1960s, however, such gains have leveled off. “Today’s coal plants are approaching the fundamental limit of the iron-based steel used in turbines, boilers, pipes, and other components,” said Jeffrey Phillips, a senior program manager at EPRI. “Once the temperature gets above 1100°F, the steel loses strength. If we want higher efficiencies, we have to use different materials.”

Improving efficiency through more rugged materials results in burning less coal and emitting less CO_2 to produce a given amount of electricity. According to Phillips, operating coal plants at 1400°F would result in a 20% emissions reduction and a 24% increase in thermal efficiency relative to the current U.S. coal fleet average. Increasing a 500-megawatt coal plant’s thermal efficiency by 24% could potentially yield a savings of $10–15 million in annual fuel costs.

Testing Nickel Alloys in the Field

For 15 years, EPRI has collaborated with utilities, government agencies, and equipment manufacturers to test the strength of plant components made of nickel alloys. “These laboratory tests tell us that we have a material that can withstand 1400°F,” said John Shingledecker, program manager of EPRI’s fossil materials research. “Now we need to prove these materials in an operating power plant.”

Enter the Advanced Plant Component Test Facility, slated for Youngstown, Ohio. Funded by the U.S. Department of Energy (DOE) and the Ohio Coal Development Office through grants to Energy Industries of Ohio, the public-private initiative plans to retrofit a coal-fired heating facility with nickel alloy components—such as a 7-megawatt steam turbine—and then operate it at 1400°F for two years, starting in September 2018. The project also is funded by EPRI and equipment manufacturers Babcock & Wilcox Company and GE.

As the project’s technical lead, EPRI is coordinating participants, advising construction company AECOM as it executes facility engineering and design, and issuing progress reports. Babcock & Wilcox is designing the superheater that will produce steam at 1400°F, while GE will design and build the steam turbine. Energy Industries of Ohio is providing project management and coordinating financial, contractual, and administrative matters. DOE is helping to guide the project by setting technical goals. Oak Ridge National Laboratory is supporting materials selection.

For testing flexibility, the coal-fired plant will not connect to the grid and generate electricity, as the facility did in the past. One priority is to examine how plant cycling affects the nickel alloy. “Fossil power plants are doing a lot of cycling today to accommodate variable wind and solar generation,” said Phillips. “We will simulate starting and shutting down the plant 2,000 times by putting the equipment through 2,000 thermal cycles.”

After the plant is operated for at least 8,000 hours, key sections will be sliced into pieces and examined under microscopes for cracks, chemical changes, and other signs of deterioration.

Phillips expects that a successful demonstration of the nickel alloy would lead to a more ambitious project. “We could have a 500-megawatt plant tied to the grid and designed to operate for 30 years,” he said.

The more efficient plants built with these new materials could help utilities meet the New Source Performance Standards. “Plants with higher efficiencies burn less coal to produce the same amount of electricity—and that means lower CO_2 emissions,” said Phillips. “Using today’s coal plant technology, you have to capture and store about 30% of the CO_2 to help new plants meet those standards. If you use higher temperatures and efficiencies, you could only have to capture about 15%.” In addition, retrofitting this technology into existing coal power plants could help states meet the CO_2 emission reductions required by the Clean Power Plan.

Key EPRI Technical Experts

Jeffrey Phillips

R&D Quick Hits

Non-U.S. Sources Contribute Most Mercury to San Juan River Watershed

When EPRI combined atmospheric and watershed modeling to look at the fate of trace metal emissions across the San Juan River watershed, the research indicated that from 2020 to 2044, the coal-fired Navajo Generating Station will contribute less than 1% of mercury deposition, with 3% coming from all other North American sources (including local power plants), 16% from China, and 80% from the rest of the world.

The watershed includes portions of Arizona, Utah, New Mexico, and Colorado, and the research confirms results of a similar EPRI study of the Four Corners Power Plant in New Mexico—which revealed the growing dominance of non-U.S. sources as U.S. emissions drop.

Projections account for different plant operating scenarios along with projected emissions from China, the world's largest source of man-made mercury emissions.

Other findings: Through 2074, the Navajo Generating Station will contribute a maximum of 0.035% of mercury in fish tissue in the watershed and a maximum of 0.44% of selenium in surface waters. The plant's contribution to surface water arsenic concentration is less than the 0.01% discernible by the watershed model.

While this research is helpful in informing a potential decision to extend the plant's site lease, it also points to the importance of fully understanding the multiple sources of a pollutant when permitting a specific power plant.

R&D Quick Hits

An Emerging Cure for Charging Anxiety

Wireless Power Transfer Is Booming Area of Innovation and Product Development

An EPRI study has found that "wireless power transfer" offers a potential technological cure for charging anxiety—which affects electric vehicle drivers, cell phone users, and traveling office workers with laptop computers. EPRI examined a range of innovations, navigating more than 300 companies offering about 800 products as of mid-2015, where technologies most used rely on inductive coupling and resonant coupling.

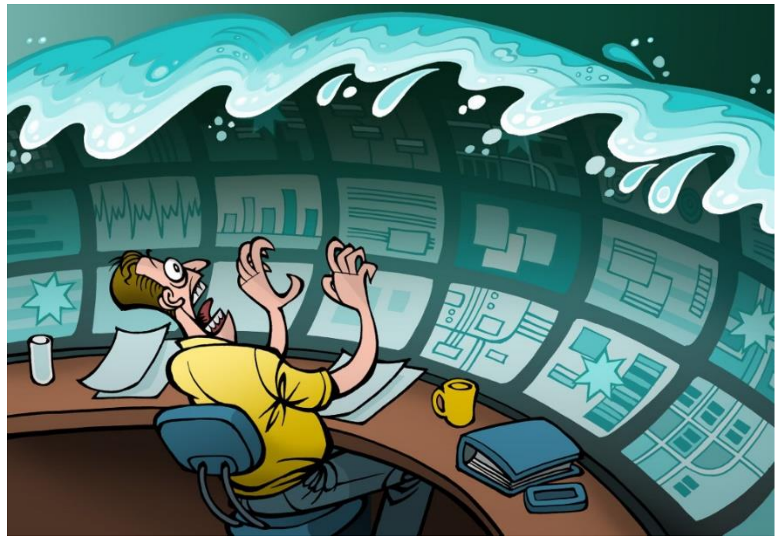
EPRI's research provides a broad look at diverse technologies and applications, including:

- Promising electric utility applications include power plant sensors, in-motion electric vehicle charging, and power delivery during outages after major storms.
- Major companies such as IKEA, AirCharge, McDonalds, and Marriott have deployed wireless chargers for mobile devices in their products and facilities.
- Researchers are exploring diverse breakthrough technologies, such as transmitting power by light and "beaming" power from solar plants in space to receivers on earth.
- Environmental benefits through elimination of batteries, power cords, wires, and other charging infrastructure for personal electronics.
- Potential safety risks—such as injuries that may occur when people or animals cross wireless power transmission paths—still need to be investigated.

R&D Quick Hits

From Data Tsunamis to Information Bursts

Can Lessons from Google and Twitter Help Utilities Run the Grid?



As electric utilities rapidly deploy sensors, smart meters, and other hardware for more comprehensive awareness of the grid, they may have something to learn from Google and Twitter.

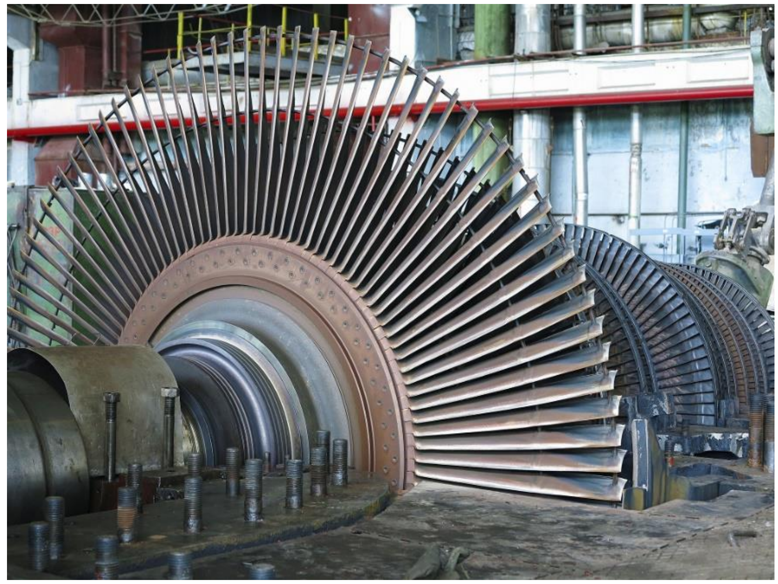
With the daunting prospect of centrally processing a tsunami of data from these devices, EPRI researchers have proposed a distributed approach: Each device processes its data into much smaller, actionable "information bursts" and transmits them to grid operators in standard message formats—similar to the way texts, tweets, and photos are sent from smart phones. Operators could manage and integrate these messages using software and methods similar to those used by Google and Twitter to visually represent tens of millions of texts and tweets per minute. Operators could then track integrated messages for real-time and historical snapshots of grid status.

For example, instead of transmitting megabytes of unprocessed customer use data, a smart meter would transmit only the most relevant bytes of aggregate data for a certain period, along with outage notifications when power is interrupted.

EPRI is working with the University of North Carolina at Charlotte to develop and demonstrate a message manager prototype and data structure. The project will assess computing requirements and necessary modifications in grid hardware.

R&D Quick Hits

A Protective "Lozenge" for Steam Turbines



Study: Film-Forming Products Can Mitigate Corrosion and Deposition of Contaminants During Power Plant Shutdowns

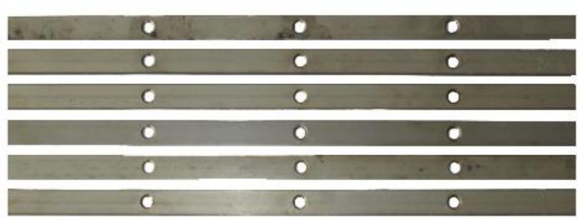
Film-forming products may soon become the trusted "throat lozenges" for power plant steam turbines. In a first-of-its-kind field study, EPRI demonstrated that these chemicals' ability to form a protective layer on metal surfaces can significantly reduce corrosion in low-pressure turbines during plant shutdowns and layups. This finding supports their use in the steam/water cycle prior to shutdown.

Plant shutdowns may alter steam chemistry in the phase transition zone.

In a test loop deployed at Duke Energy's Marshall Steam Station Unit 3, researchers installed strips of carbon steel and a stainless steel alloy containing chromium (similar to that used in steam turbines). They injected film-forming products from several manufacturers, along with corrosive contaminants such as chloride and sulfate, into low-pressure steam as it was diverted from the Marshall unit into the loop. After the loop was cycled on and off for two weeks, researchers assessed the steam's corrosivity based on the number and size of pits on the strips. Results demonstrated the film-forming products' superior protective ability to arrest pitting on the strips during plant shutdown and layup conditions relative to conventional steam chemistry.

The study's authors point to the importance of carefully evaluating each film-forming product before use because some may contain constituents that could adversely impact steam/water cycle components.

Corrosion on a set of strips that were not treated with film-forming products



Minimal corrosion on a set of strips treated with film-forming products

R&D Quick Hits

From Flying Wind Turbines to Robotic Birds of Prey

Scouting Technologies That Fly, Float, and Focus

Yes, it's true. Wind turbines can fly—or at least one prototype that is attached to a helium-filled blimp.

EPRI Innovation Scouts are investigating the airborne turbine, along with concepts and technologies spanning diverse aspects of wind power generation, including:

- Enhanced towers, foundations, blades, rotors, generators, and other turbine components
- Novel concepts for onshore and offshore turbines
- Wind measurement devices
- Turbine monitoring systems
- Systems to transport heavy components
- Offshore energy storage
- Wildlife protection

Wind power costs and performance have improved significantly over the past decade, but many hurdles to mass deployment remain, such as siting constraints, high upfront capital costs, and adverse impacts on wildlife. Scouting reports point to many promising technologies to address these.

Here's a sample:

Photo courtesy of Vortex
Developed by Vortex, these prototypes of bladeless cylindrical turbines generate electricity by oscillating in the wind.

Potential benefits: Reduced capital, maintenance, and generation costs relative to conventional blade turbines

Challenges: Lower energy harvest and conversion efficiency

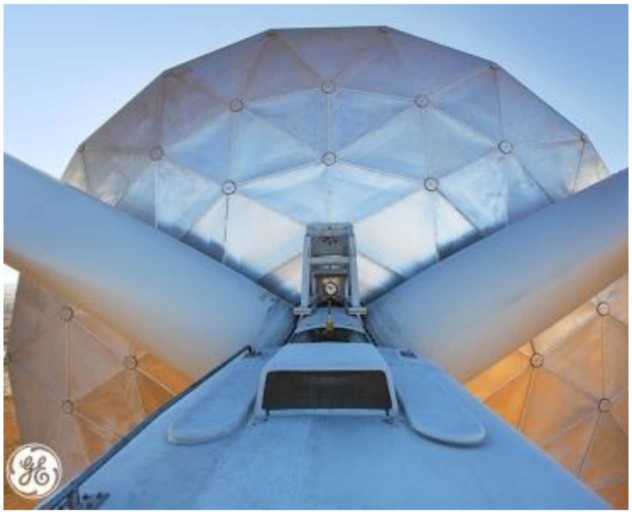


Photo courtesy of GE
This GE prototype bolts an aluminum dome to the rotor, deflecting wind to blade tips for greater power harvest.

Potential benefits: Higher power rating; enables shorter blades

Challenges: Impact of dome's size and weight on turbine structure and installation

Image Provided by Prof. T. Ohta, Kyushu University
The Research Institute for Applied Mechanics at Japan's Kyushu University uses a distinctive wind lens to draw more wind into offshore turbines. In this concept, multiple turbines can be deployed on floating platforms rather than seabed-mounted towers. Note that this image is synthetic.

Potential benefits: Increased power output; lower electricity costs

Challenges: Accurate control of the assembly's orientation to optimize the wind-focusing effect

Image courtesy of Nenuphar
Nenuphar's floating offshore turbine positions blades around a vertical shaft. Note that the image is a synthetic photograph; the turbine is a prototype and not yet installed offshore.

Potential benefits: Lower capital and installation costs relative to horizontal-axis turbines; generator positioned closer to sea level for greater stability and easier maintenance

Challenges: Developing commercial-scale units; long-term reliability and efficiency

Photograph courtesy of Altaeros Energies
A prototype from Altaeros Energies attaches the turbine to a helium-filled, ground-tethered blimp to generate power from high-altitude, high-speed winds.

Potential benefits: Higher output and lower electricity cost relative to land-based turbines; no land-based siting constraints; no towers or heavy cranes needed for deployment; less risk to birds

Challenges: Developing commercial-scale units; long-term reliability; new regulatory framework required

Photograph courtesy of Clear Flight Solutions
Developed by Clear Flight Solutions, this commercially available robotic bird of prey (peregrine falcon) is intended to keep birds away from wind turbines, preventing collisions.

Potential benefits: Reduced environmental impacts and resulting wind power curtailments

Challenges: Bird habituation to robots

When these and other emerging technologies are ready for field demonstration, EPRI will work with member utilities to assess their performance under actual operating conditions. Members who want more information on demonstration-ready technologies can contact techexpert@eprijournal.com.

An Innovation Scouts presentation on wind power technologies is available to EPRI funders.

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