SPRING 2014

EPRI JOURNAL

ELECTRIC POWER RESEARCH INSTITUTE

Integrated Grid

ALSO IN THIS ISSUE:

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RESEARCH INSTITUTE

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WIRED IN

Perspectives on electricity

Colton K. Ching
Vice President, Energy Delivery
Hawaiian Electric Company

Hawaii: "Walking Point" with Record Level of Rooftop Solar

Utilities across the nation are facing a dramatic increase in distributed generation. With more than 11% of our customers equipped with rooftop solar photovoltaics, Hawaiian Electric Company is in the vanguard.

Rooftop solar is an important part of our energy portfolio. Along with wind, biomass, utility-scale solar, small hydro, and geothermal, it helped us achieve a 2013 Renewable Portfolio Standard of 18%—far ahead of our mandated goal of 15% by 2015, and on the way to 40% by 2030.

The tough part of "walking point" is that the trail ahead is not clearly marked. Some neighborhoods have reached high levels of rooftop solar that require us to take extra steps to ensure reliability and safety for our customers and employees.

Rooftop-generated electricity exceeds 100% of daytime minimum load on more than one-fourth of the distribution circuits on Oahu. We've had to sharpen interconnection procedures and allow time for detailed studies to identify possible mitigation measures on some circuits. These precautions frustrate many customers hoping to join the solar trend to reduce their electric bills, which are unusually high due to Hawaii's dependence on expensive oil imported from the Middle East and Asia.

We can't shortcut on our responsibility for safety and reliability, and we are aggressively addressing technical challenges in many ways, including collaborative R&D to:

- Further our understanding of PV impacts on high-penetration distribution circuits
- Develop better planning and operational tools
- Deploy storage technologies
- Increase operational flexibility of our fossil-fired units
- Enhance demand response programs

For example, with the University of Hawaii's Natural Energy Institute, we have multiple projects evaluating battery technology to open our grid to even greater concentrations of variable renewables.

We're a partner in the U.S./Japan JUMPSmart Maui smart grid demonstration, focused on managing clean energy resources using smart grid devices to control photovoltaic systems and an electric vehicle–charging network in volunteers' homes.

We are strategically siting irradiance and wind sensors throughout our islands to give our system operators better solar and wind forecasting capability.

Through research, testing, and growing experience with high levels of solar, we are identifying low-cost solutions to some technical challenges. For example, to address transient over-voltage risks, customers can get the okay to install new photovoltaic systems as long as they include approved fast-trip inverters or automatic transfer devices. This measure allows solar capacity on distribution circuits of up to 120% of daytime minimum load.

These initiatives are part of our larger endeavor to use advancing technology effectively to change our grid to meet evolving customer needs. We've just embarked on a major smart grid rollout with plans to install advanced meters for all of our 450,000 customers on Oahu, Maui, Molokai, Lanai, and Hawaii Island. In addition to customer benefits such as faster outage restoration and online electricity-use tools, our smarter grid will provide a more accurate view of the distributed solar output to manage it better in the future. This technology is the foundation of efforts to increase integration of renewable energy.

We also welcome EPRI's Integrated Grid concept, aimed at developing a comprehensive framework for addressing the many challenges—technical, regulatory, economic, and others—that come with an increasingly distributed energy system.

For more than a century, utility distribution systems were built and expanded to carry power only one way. With customers now generating their own energy, we must adapt—in a fraction of that time—to allow power to flow in many directions at once.

We see our critical future role less as a generation company and more as the grid operator enabling the integration of low-cost renewable energy—both central and distributed—while sustaining safe, reliable service.

At Hawaiian Electric, we are committed to overcoming these challenges—and to setting an example as we meet our high expectations for service to our customers.

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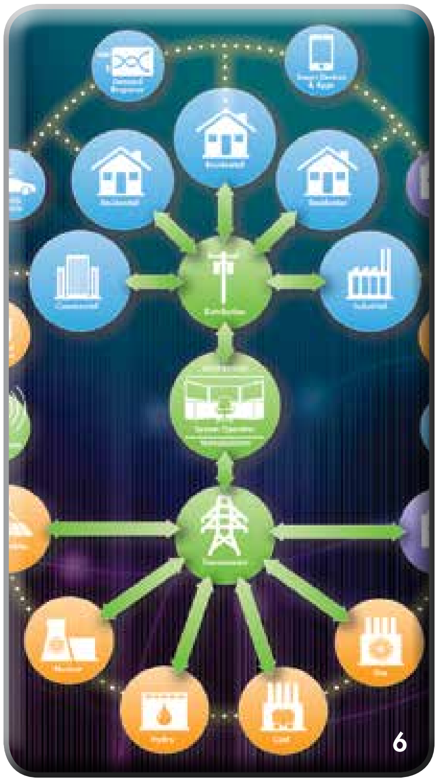


VIEWPOINT

FEATURES

DEPARTMENTS

by Mike Howard, President and CEO, EPRI

From Interconnected to Integrated

The electric power system is changing—moving toward a future power system that enables the best features and values of both central generation and distributed energy resources (DER) such as energy storage, photovoltaics, demand response, and fuel cells. In many locations, these distributed resources are already affecting the power system, and their projected expansion will likely change the technical, operational, environmental, and financial character of the electricity sector.

To fully realize the value of DER and to serve all consumers at required standards of quality and reliability, we recommend integrating DER in the planning of the all-inclusive power system—what we are calling the *Integrated Grid*.

Early in 2014, we published our concept of the Integrated Grid to help the electricity sector chart this course. (See the cover story in this *EPRI Journal*.)

We introduced the concept as consumers in markets such as Arizona and Hawaii are adopting rooftop solar—and as others are using smart phone apps to manage energy use in new ways. Both examples point to products and services that will transform the power grid to a dynamic system in which electricity, data, and information are moving in many new directions. Some experts and prognosticators have declared the old power company business model obsolete, and some declare that electricity providers are resisting change, clinging to an outdated status quo.

As I look over the horizon, I see a different picture. Like others who are sharply focused on the future, I see change coming, but I don't see systematic resistance to change. Rather I see people—in different ways and in different contexts—calling on us to approach this transformation carefully and systematically. The aim is to realize the full value of the power system while incorporating all the changes, but continuing to provide electricity that is safe, affordable, reliable, and environmentally responsible.

With rooftop solar or gas-fired microturbines, consumers will assume the dual role of electricity user and producer, while continuing to expect the value of the grid's capacity to serve their individual electricity demands every second and hour of the day. To meet this new dual role, we must transform from a one-way grid of interconnected parts, to an integrated grid.

Already, different utilities are moving at different paces in integrating DER, demonstrating the importance of consistent methodologies in determining their benefits and costs in different areas. Rooftop solar means one thing in sunshine-rich Arizona, but it means something else in Montana. Already we know that the characteristics of individual distribution lines or "feeders" point us toward diverse arrays of technologies and operating systems.

There will be many different ways to integrate distributed and central energy resources, but we must focus on keeping the system's backbones strong. As we deploy new information and communications technologies, we must keep the new central nervous system whole and healthy.

EPRI is working to develop a common tool set for the work ahead on planning, policy, standards, and interconnection rules. There won't be a one-size-fits-all Integrated Grid, so it's important to bring the best insights of science, engineering, and operations from everyone who has a stake in the outcome. By applying these insights systematically, we can take the grid from one of interconnected parts to one that integrates distributed and central resources to realize a whole new level of reliability, affordability, and environmental responsibility.

I invite you to read much more about the transformation to the Integrated Grid in this issue of the *EPRI Journal*.

Michael W. Howard
President and Chief Executive Officer

SHAPING THE FUTURE

Innovative approaches to upcoming challenges

Grid-Scale "Surge Protector" Moves Through Lab Tests, May Offer Cost-Effective Improvements in Grid Protection

EPRI is developing a technology that could help utilities cost-effectively address the expensive—and growing—problem of excess current flowing through the electric system under fault conditions. The device, called a *fault current limiter*, may be a simple solution to a challenge that will otherwise require redesign of grid infrastructure.

Growing Risks from Excess Current

Short circuits in the grid, called *faults*, can result from lightning, crossed or downed power lines, and other unintended contact on components. During a fault, a surge of current known as *fault current* flows through the electric system, potentially overloading and damaging grid components.

With a rise in demand and more distributed generation, fault current levels in the transmission and distribution grids have steadily increased, especially in urban areas. Many grid components were designed to handle the lower fault current levels observed 20–30 years ago.

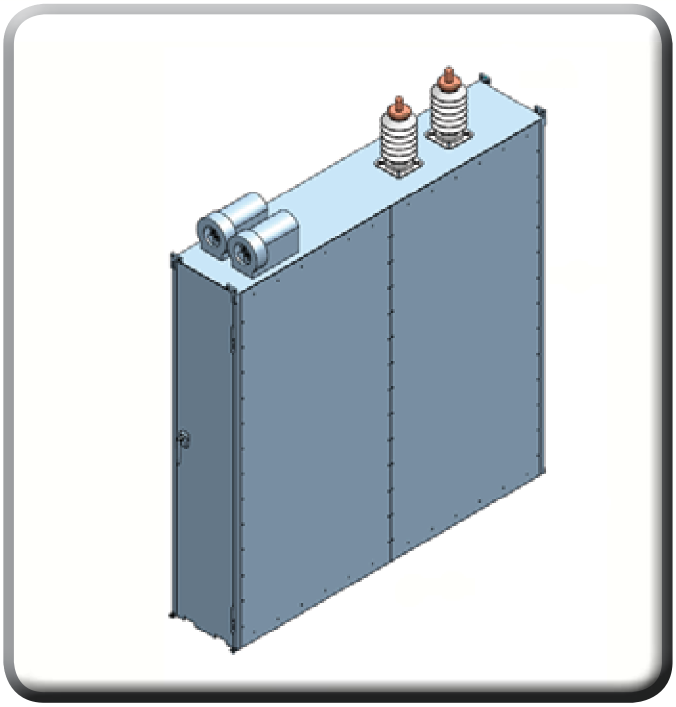
A particular concern among utilities is that current levels increasingly exceed the rated limits of existing circuit breakers—the electrical switches in substations and other parts of the grid that interrupt fault currents to protect the entire system.

"There is a growing risk of circuit breaker failures and resulting power outages," said EPRI technical leader Ram Adapa. "Without an effective approach to reduce fault currents, utilities may soon have to replace as many as 80% of their circuit breakers with units rated for higher current. This would require redesign of substations and other major infrastructure."

Current-reducing devices typically used today have technical drawbacks and cost utilities millions of dollars each year. Fuses blow when exposed to high current levels, require a service call for replacement, and are not available for high-voltage transmission systems. Series reactors (insulated coils cast in concrete) are bulky and cause power losses and grid voltage drops. Some utilities have implemented relatively expensive, short-term fixes such as splitting buses, which are the metal bars in distribution substations that conduct large amounts of electricity.

A Surge Protector for the Grid

Since 2007, EPRI has been developing a fault current limiter—a device that absorbs the fault current's excessive energy and prevents it from reaching utility assets. These are similar to the familiar surge protectors that protect household appliances. Based on high-speed, solid-state switching devices, the technology can respond to faults within 100 microseconds and can eliminate the need to replace existing circuit breakers.



A drawing of EPRI's single-phase fault current limiter

With the U.S. Department of Energy, EPRI has built a single-phase prototype for distribution systems rated at 15.5 kV. EPRI has successfully factory-tested the device for several key functions, such as current limiting, and plans more tests at an independent laboratory this year—including an evaluation of how the device responds to lightning. If laboratory tests are successful, EPRI will build and field test in 2015 a unit for three-phase power systems. If the technology is proven for distribution systems, EPRI will build and test a device for 69-kV and above transmission systems.

The fault current limiter is intended for a variety of applications in distribution and transmission grids, major commercial and industrial loads, and megawatt-scale distributed generators. In addition to reducing grid maintenance costs, it offers the potential to increase grid safety and reliability, reduce blackouts, and support the addition of new generation capacity. Through real-time monitoring, it may also make grid conditions more visible to system operators.

For more information, contact Ram Adapa, radapa@epri.com, 650.855.8988.

Energy Efficiency Can Reduce U.S. Electricity Consumption in 2035 by 8–11%, Study Finds

By 2035, energy efficiency programs have the potential to reduce annual U.S. electricity consumption by an amount equivalent to the annual output of at least 100 typical natural-gas-fired power plants, according to a recent EPRI study. The research estimates the potential electricity savings and peak demand reductions from voluntary customer participation in utility- or state agency–sponsored energy efficiency programs through 2035. The report (1025477) is an update to previous EPRI research published in 2009.

A National Study to Inform Utilities and Policy Makers

Energy efficiency gains are cost-effective ways to reduce emissions and utility bills. A key objective of EPRI's research in this area is to provide fact-based estimates of energy efficiency potential to inform utilities and policy makers. Because adoption of energy efficiency may reduce electricity use, such research can help utilities incorporate a better understanding of future demand growth in resource planning.

EPRI's analysis is based on detailed technology performance and cost data, including findings from EPRI laboratory testing and field evaluations. It considers currently available technologies and the likely evolution of product efficiencies and costs. It also reflects observations of real-world efficiency programs and accounts for market barriers such as customer inertia and supply chain constraints. The study provides a national scope and a "bottom-up" methodology based on equipment stock turnover and consumer adoption. This results in more detailed savings estimates by region, customer sector, building type, end use, and technology. (National studies typically use "top-down" approaches based on macroeconomic data, yielding less detailed estimates.)

Research Results

For a baseline projection of electricity demand, EPRI used the U.S. Energy Information Administration's 2012 Annual Energy Outlook (AEO), which estimates that U.S. electricity consumption will increase from 3,722 to 4,393 terawatt-hours between 2012 and 2035, for an average annual growth of 0.72%. This forecast already accounts for energy efficiency adoption resulting from the federal ENERGY STAR® labeling program, federally legislated appliance standards and building codes, and the continued impact of state and utility efficiency programs launched prior to 2012.

EPRI's research focused on potential gains above and beyond the levels included in the AEO forecast. Assuming budgets and execution proficiency typical of today's energy efficiency programs, EPRI found that efficiency programs have the potential to reduce the forecasted 2035 electricity consumption by 8%, or 352 terawatt-hours. For context, 352 terawatt-hours is equivalent to the annual energy produced by 100 natural-gas–combined-cycle power plants, each with a capacity of 550 megawatts. EPRI also calculated a "high achievable" scenario reflective of exemplary efficiency programs that overcome budgetary and execution barriers—which yielded an 11% reduction in 2035 electricity consumption, or 494 terawatt-hours.

Other key findings:

- Efficiency programs have the potential to reduce the projected 2035 summer peak demand of 714 gigawatts by 79–117 gigawatts, a decrease of 11–16%.
- Efficiency programs have the potential to reduce the projected 2035 winter peak demand of 628 gigawatts by 64–89 gigawatts, a decrease of 10–14%.
- The end use with the highest efficiency potential is commercial indoor lighting, representing 38% of the total achievable savings in 2035.
- Other applications with high potential are residential and commercial air conditioning, commercial office equipment, residential water heating, and consumer electronics.
- The commercial building segments with the greatest efficiency potential are retail and large office.

For more information, contact Omar Siddiqui, osiddiqui@epri.com, 650.855.2328; Chris Holmes, cholmes@epri.com, 865.218.8116; or Sara Mullen-Trento, smullen@epri.com, 865.218.8002.

THE INTEGRATED GRID

EPRI Charts a Course to the Power System of the Future

THE STORY IN BRIEF

EPRI's Integrated Grid initiative seeks to incorporate distributed energy resources into planning and operations of the existing grid so that society can tap the benefits of both. It provides a comprehensive framework for electricity industry stakeholders to collaborate on policies, processes, and technologies—setting a course toward a grid that is greater than the sum of its parts.

The grid is changing. For the century-plus that the power system has reliably served businesses and homeowners with the electricity required for economic growth, innovation, and comfortable lives, the grid has been a one-way street from big generators and wire systems to individual customers.

But those who read past the headlines know that with the rapid growth of distributed energy resources (DER) such as rooftop solar, the grid is on the verge of fundamental change in some areas and already changing rapidly in markets as different as Germany, Hawaii, and parts of California. "Power is being generated at individual homes and businesses and feeding into the system. With that happening, the grid starts to become, in portions of the distribution level, analogous to a two-way street," said Hank Courtright, EPRI senior vice president of global strategy and external relations.

In many locations, updates to the grid's infrastructure have not kept pace with the emergence of this "two-way" power flow. The rapid deployment of DER poses real challenges to the power system. It's similar to changing a one-way road network to a two-way system overnight.

The Integrated Grid Initiative

While the traffic analogy may be simplistic, it provides a conceptual link to the changes faced by grid planners and operators. Benefits may be huge eventually, but a swift, ad hoc influx of DER could challenge reliability and affordability in the short term. Hoping to avert avoidable expenses and disruptions in service while embracing the advantages presented by DER, EPRI has launched a multiphase initiative known as the *Integrated Grid*.

As a concept, the Integrated Grid is about incorporating DER in the planning and operations of the existing grid so that society can fully tap the benefits of both grid-connected service and distributed resources. "We want electricity to remain a product that can continue to unleash innovation and do it by integrating these new resources in a way that is beneficial to society," said Arshad Mansoor, EPRI senior vice president of research and development. "You don't do that by going off-grid, and you don't do that by saying you can't connect to the grid because you're going to impact reliability. There needs to be clarity on the engineering and technical aspects of how you can integrate what was already there and what we see coming."

As its first step toward finding that clarity, EPRI in February released a white paper to introduce the Integrated Grid concept; to outline four areas to focus research, development, and demonstration programs; and to propose next steps in those key areas.

The concept paper reflected input from a variety of stakeholders, including utilities, regulators, equipment suppliers, and non-governmental organizations. It drew on the experience of regions in which DER has already achieved high penetration as well as analysis of questions that need to be addressed to cost-effectively and equitably modernize the grid. It lays the foundation for a fact-based discussion of this transformation.

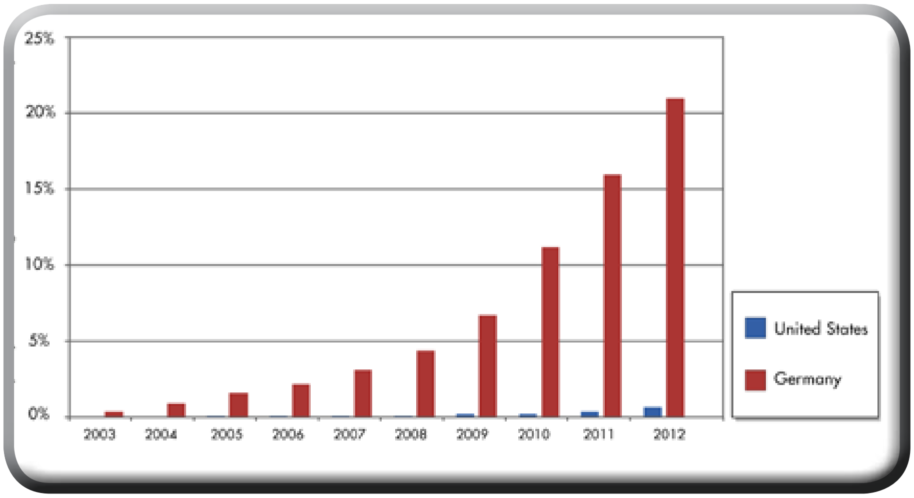
As part of the initiative's second phase, EPRI has already begun to develop a framework to assess the benefits and costs of different technology combinations that support an integrated grid. As proposed, Phase 3 will include technology demonstrations and modeling, using methodologies developed in Phase 2 to provide comprehensive data that decision makers need to cost-effectively deploy integrated grid technologies.

These days, it is common to encounter pronouncements that the growth of solar photovoltaics (PV) paired with battery storage spells the inevitable disappearance of the grid—along with predictions that too much DER will sink the reliability of the power system. The Integrated Grid initiative is an effort to get past rhetoric to chart a realistic, common path forward for all concerned.

The Lesson from Germany

It may strike some as odd that so much attention is being paid to the potential impact of resources that, at first glance, seem insignificant. At the end of 2013, PV installations in the United States totaled 10 gigawatts. While this is a dramatic increase from past years, it still amounts to less than 2% of total installed generation capacity in America.

But size can be deceiving. In fact, PV penetration in the United States is about where Germany was 10 years ago. "If you go back to 2003, less than 1 percent of German installed capacity was PV," said Ron Schoff, program manager for EPRI's Technology Innovation program. "A



PV capacity in the United States and Germany, 2003–2012, expressed as a percentage of total generation capacity

decade later, it's more than 20 percent. That is a huge deployment of PV in a short period of time."

Germany's experience offers important lessons. The explosive deployment of distributed solar in Germany was intentional: a generous feed-in tariff offered homeowners and businesses significant financial incentive to install power production technology for their own use and to feed back to the grid. But what was not anticipated by grid planners and operators was the impact on the grid from such a large combined variable resource. "They let the deployment of technology get ahead of the changes they needed to make and the analysis they needed to do to make sure the system could accommodate this new type of power flow," said Ben York, an EPRI engineer. "Many of these changes are better made proactively than retroactively."

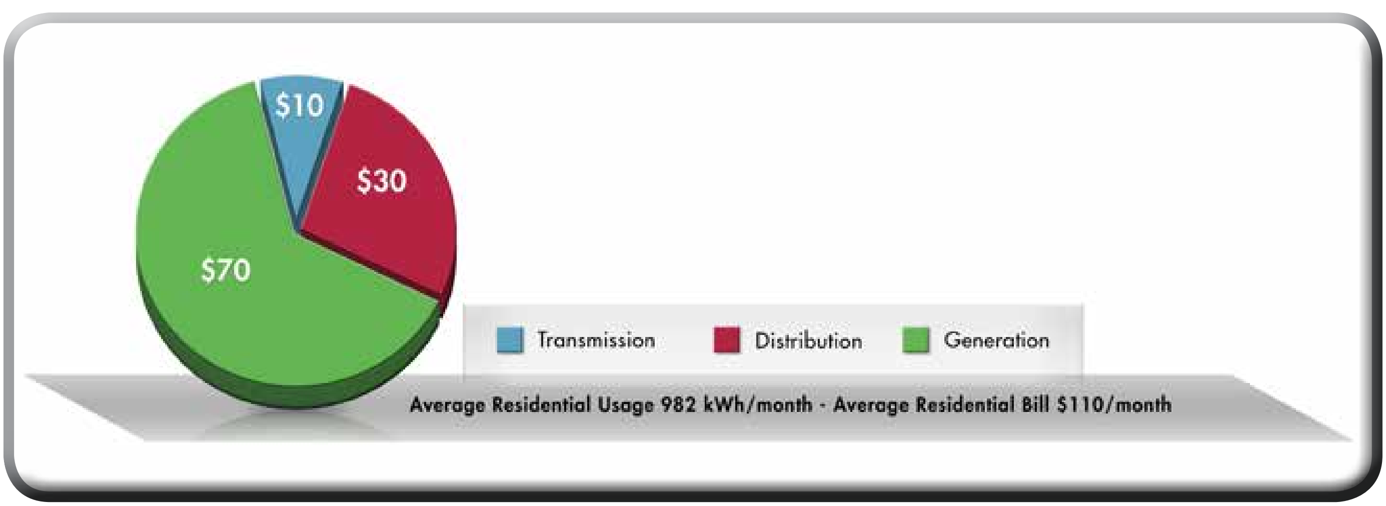
Case in point: Germany has had to revise its grid codes and standards, requiring PV installations to include smart inverters that provide voltage stability and ride-through in response to faults and other disturbances. The need to retrofit an entire nation's PV installations with just one functional change comes with a price tag of nearly $300 million.

Germany's challenges offer a real-world lesson about the right approach to grid modernization that includes—and benefits from—a large, widespread deployment of DER. "By not anticipating all these things and solving the entire problem, you can invest large sums of money to build out what you think is a smart grid today," said Bernie Neenan, EPRI technical executive. "But then tomorrow you realize it isn't so smart because you left something out and didn't have a big enough perspective."

Integration Recommendations

In studying the experiences of places with large deployments of DER, such as Germany and Hawaii, the paper's authors outlined recommendations to help the United States chart a smooth road to an integrated grid. These recommendations are rooted in the premise that optimal grid operation is possible only with a commitment to meld the benefits of DER and central station resources into one integrated power system. Accomplishing that will require cooperative development and implementation of new policies, processes, and technologies.

For instance, EPRI recommends that stakeholders develop rate structures that accurately value both capacity and energy so that the entire power system can best serve customers. To see why the current approach to rates isn't adequate with a lot of DER, it's helpful to understand the difference between energy and capacity. *Energy* is the kilowatt-hours we need to run our air conditioners and hair dryers. By contrast, *capacity* is the electric infrastructure's maximum capability to supply



Cost-of-service breakdown for today's grid-connected residential customer and deliver a given level of energy at any time.

Today, a typical power bill doesn't include separate charges for capacity and energy. "Most consumers pay a volumetric rate, meaning that they pay their electric bill based on how much energy they use," said Schoff. And therein lies a problem. In some jurisdictions, it's possible for customers with solar arrays to have monthly electric bills of nearly zero if their panel generation matches their energy use. In other words, they could be paying next to nothing, even while receiving important capacity-related benefits from the grid.

Another recommendation in the paper is to update interconnection rules and, in particular, require the use of grid-benefiting smart inverters for PV installations. "Inverters enabled with smart functions can support voltage and provide support for the grid during faults and other abnormal conditions," said York. "Right now, the codes and standards aren't in place to enable that. If we work to update those standards, which the industry is doing right now, it will enable the necessary functions." Examples include California's ongoing revision of its interconnection standard, known as Rule 21, and the development of IEEE 1547a, which is an update of the current DER interconnection standard.

Other recommendations include establishing common language and information models that enable interoperability among various kinds of DER, as well as tools that allow grid planners and operators to use DER to meet loads under extreme conditions. Mansoor says that tackling these issues in a cooperative way provides the opportunity to "strengthen the foundation that built the grid and also bring in value from these new resources."

The Road Ahead

Although EPRI's initiative recommends effective ways to achieve an integrated grid, it does not prescribe specific actions in specific locations. There is a clear understanding that regional differences will result in varying decisions about the best DER technologies and policies. EPRI is laying out important facts and methodologies—a toolbox—for the electricity industry to use. "The word 'accommodation' is important," said Bernie Neenan. "We optimize within boundaries that people set, and there is no reason that people have to come to the same solutions."

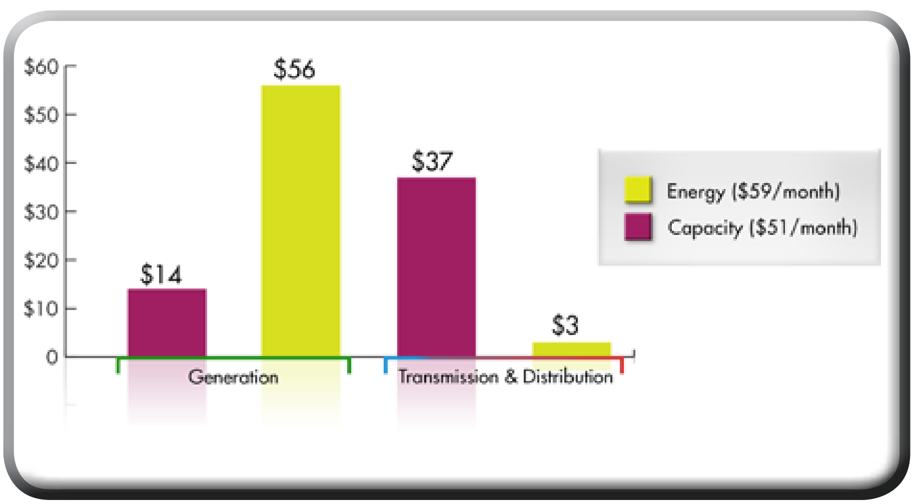
The next two phases of the Integrated Grid initiative will provide more detailed information and examples to guide stakeholders and decision makers. In Phase 2, EPRI is developing a framework to assess the benefits and costs of various technology combinations that lead to an integrated grid. Ultimately, this will result in guidelines, analytical tools, and procedures for demonstrating technologies and quantifying their unique costs and benefits. This is a big-picture approach to understanding the evolution of the grid that has never been done before.

Phase 3 will take the analytics and procedures developed in the second phase of the Integrated Grid effort and apply them to global demonstrations and modeling. The goal is to provide stakeholders with the real-world information they need to implement integrated grid technologies cost-effectively.

A central goal of EPRI's initiative is to point to pathways in which collective action can work in everyone's best interests. "The basic action plan laid out here is for technologists, utilities, regulators, policymakers, solar developers, and others to get on the same page and head in the same direction," says Ron Schoff. "If you couple a clear plan for deployment of DER with equitable enabling policies, regulations, and standards, it's our opinion that you will end up with an optimum power system. That is the theme—getting everyone to work together."

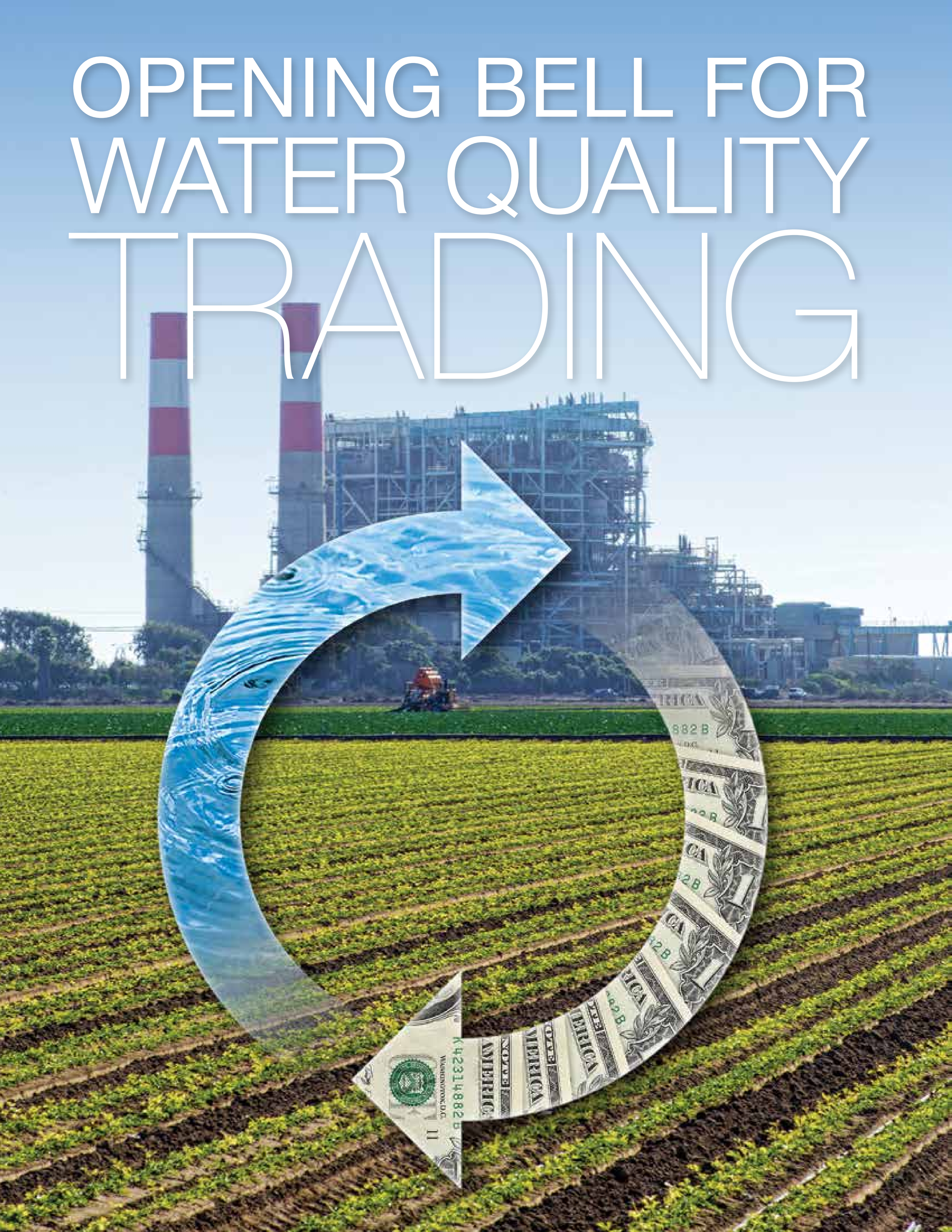
This article was written by Chris Warren. Background information was provided by Ron Schoff, rschoff@epri.com, 704.595.2554.

Ron Schoff is the senior program manager of EPRI's Technology Innovation program. He is focused on thought leadership and manages a strategic research portfolio to help shape the future of the electricity industry with an increasing emphasis on disruptive technologies. Prior to joining the Technology Innovation program, Schoff conducted advanced coal plant and CO_2 capture research in EPRI's Fossil Fleet for Tomorrow program. He holds a BS degree in chemical engineering from the University of Pittsburgh and an MS degree in chemical engineering from Villanova University.



In considering the value of the Integrated Grid, costs of generation, transmission, and distribution can be determined for energy and capacity.

OPENING BELL FOR WATER QUALITY TRADING



THE STORY IN BRIEF

EPRI's Water Quality Trading initiative—the largest such project in the world—has transacted the first trades between farmers and power companies in the Ohio River Basin. By demonstrating trading's feasibility and benefits, the initiative can help spur its broader adoption.

In 2011, the head of a state agriculture agency asked EPRI technical executive Jessica Fox to meet with some local soil and water conservation district representatives over lunch to discuss an idea to launch a water quality trading project in the Ohio River Basin. With water quality trading, power plants seeking water pollutant reductions can purchase those reductions from farmers who can potentially achieve the same reductions at lower cost. At the time, it was still a relatively untested concept that EPRI wanted to research.

Expecting an informal gathering with just a few people, Fox instead found herself in a room with representatives from more than 30 districts. "You could feel that there was skepticism and many questions to be answered," Fox recalled. When the districts told her they wouldn't support the water quality trading project, she said, "That's fine. But just so I understand, what are the concerns?"

The district representatives were uncomfortable with EPRI talking directly to farmers because they had successfully filled that role for decades—and wanted to continue doing so. After learning this, Fox expressed her eagerness to work with the appropriate state agencies to structure the project with the districts serving as the primary liaison with farmers. An hour and a half into lunch, she had the districts' support for the project, and over the next several months Fox and the state agencies hashed out the details of their responsibilities.

Fox's lunch experience reflects the hard work needed to launch EPRI's Water Quality Trading initiative, which she has been developing since 2005. Indeed, over the past five years, she has led dozens of workshops, made thousands of phone calls, and attended hundreds of meetings to explain how the project would work—all as part of an effort to build a wide-ranging collaborative among power companies, regulators, farmers, environmentalists, and other stakeholders.

Momentum behind this collaborative has grown, culminating in 2012 when Ohio, Indiana, and Kentucky signed the first interstate trading plan. In March, Fox and her team reached another milestone, with the transaction of the first water quality trades between farmers and power companies in the Ohio River Basin—making it the largest water quality trading project in the world.

How Water Quality Trading Works

Water quality trading is difficult to explain, which is why Fox's ability to deliver a compelling pitch and her willingness to listen to stakeholders have been critical to the program's progress to date. A good understanding begins with two nutrients: nitrogen and phosphorus. While they are critical to ecosystem health, too much of them can harm aquatic systems through algal blooms, fish kills, and other problems. They come from many sources, including farm runoff from fertilizer and manure, urban stormwater runoff, water treatment plant effluents, and deposition of emissions from power plants and cars.

Because nutrients are concentrated as the Mississippi River's waters are gathered and discharged into the Gulf of Mexico, the river's nutrient load is thought to give rise to the gulf's vast "dead zone," in which excess nutrients result in algal blooms that deplete the zone of oxygen and aquatic life.

Nutrient pollution can be diffuse and difficult to control. Regulators can limit discharges from point sources such as power plants, but nutrients from farm runoff are trickier to address. "Agriculture is not directly regulated under the Clean Water Act, so trying to reduce the amount that comes off farm fields requires different approaches," said Peter Tennant, executive director of the Ohio River Valley Water Sanitation Commission (ORSANCO), which sets discharge limits for the Ohio River and its tributaries.

Water quality trading offers mechanisms to integrate non-point sources, point sources, different locations, and different regulatory and compliance needs. In EPRI's Ohio River Basin trading pilot project, farmers generate credits by implementing best management practices such as planting cover crops or buffer strips, with financial support from the project. In many cases, farmers previously wanted to implement such practices but couldn't afford them.

Indiana farmer Allan Kirkpatrick, for example, had cattle walking on muddy, rutted paths, and the project provided cost-share funds to install hard limestone pads. The new surface allows him to collect the concentrated manure and spread it on his fields, reducing nutrient runoff. Such projects "make everybody's life a little bit easier," said Brian Brandt, director of the Agricultural Conservation Innovations Center at American Farmland Trust.

After soil and water conservation agencies verify that the practices are in place, EPRI uses watershed models to determine how many credits have been generated. One credit is equivalent to one pound of nitrogen or phosphorus reduction. Those credits are then entered in an online registry, where they can be purchased by nutrient-emitting point sources such as water treatment plants or power producers.

While nutrient discharges are not typically associated with electric power companies, coal-fired power plants equipped with scrubbers to remove nitrogen oxides from their flue gas may produce water effluent with nutrients. Although none of the states involved in the trading project have adopted numeric limits on phosphorus or nitrogen in most watersheds, many state regulators are developing them.

For some power companies, more stringent limits could raise the bar for compliance, making trading a viable option. "It would be much more cost-effective for us to pay farmers to put in best management practices than it would be for us to build a stand-alone treatment plant, which would be in the millions of dollars," said Tim Lohner, an environmental specialist at American Electric Power.

A common assumption about water quality trading, said Fox, is that it's a way to get the credit buyers off the hook. Fox explained that this assumption reflects a misunderstanding about how water discharge permits work. Trading can be used to meet water quality–based effluent limits, but not the technology-based effluent limits that require facilities to perform some water treatment on-site, unless specifically authorized by the U.S. Environmental Protection Agency (EPA). Trading doesn't give power plants carte blanche to pollute. Rather, it adds another option to the mix of approaches they already use to achieve pollutant reduction targets. "The real driver behind this project is the need for more cost-effective and ecologically effective ways to manage nutrient loading," said Fox.

Although EPA in 2003 adopted policies to encourage water quality trading, the practice has yet to take off. Out of more than 80 pilot projects, feasibility assessments, and trading programs in the United States, few have led to sustained, active trading. Because of its large geographic scale and longer timeframe, EPRI's project has the potential to demonstrate trading's feasibility and benefits, with possible implications for broader adoption.

Overcoming Uncertainty

One goal is to ensure that nutrient reduction achieved through trading has the same impact on water quality as the reduction that would otherwise be required without the trade. This can be challenging for several reasons. Consider that a pound of nitrogen discharged from an upstream farm will have a different impact on a downstream water body of concern—such as an estuary—than a pound of nitrogen discharged from a downstream power plant. Another complicating factor is that farms and power plants may release different forms of the same nutrient. In addition, there can be significant uncertainty in estimating nutrient reductions from farms, in part because agricultural discharges into a watershed do not come from a single point.

EPRI completed the first trades for its water quality trading project, selling 9,000 stewardship credits. Representing the buyers were (from left to right) Mitch Griggs, Duke Energy; Michalene Reilly, Hoosier Energy; and John McManus, American Electric Power.

To adjust for these factors, water quality trading programs rely on trading ratios. For example, a 3-to-1 trading ratio would require a power plant to purchase three pounds of nitrogen reduction to achieve a credit worth one pound of nitrogen reduction from its own site.

To base the program's trading ratios on solid science, Fox worked with Dr. Arturo Keller, a biogeochemist at the University of California-Santa Barbara. "We wanted to introduce modeling to quantify the difference between the point where the credit is generated and the point where the credit is purchased," Fox explained.

Keller and his colleagues developed a watershed-scale model that takes Ohio River Basin hydrology into account. They linked model outputs to the online trading registry so that it could automatically calculate a unique trading ratio for each transaction based on the locations of the buyer and seller. The registry uses the ratio to calculate the cost for prospective credit buyers, who must be located downstream from the farm. "It will make it very easy for a buyer," Keller said.

But questions remain. Some stakeholders are concerned about how regulators will ensure compliance if states adopt numeric water quality limits. Under a trading scheme, the water quality permit holder could potentially achieve compliance by buying credits from multiple farmers. This could lead to situations in which watershed nutrient levels are not reduced, and the origin of the problem is unclear. ORSANCO's Tennant pointed out that this is exactly the kind of question that the pilot program is intended to investigate and resolve. "We can address the problems that we know about and the ones that we haven't thought of yet," he said.

From Stewardship to Compliance

In March—nearly a decade after Fox began developing the trading project—she and her team launched the online registry and

completed the program's first trades, in which Duke Energy, Hoosier Energy, and American Electric Power purchased 9,000 credits.

Currently, EPRI's trading program offers only stewardship credits, which are for the public benefit and cannot be used for regulatory compliance. Still, these early transactions have many benefits for EPRI's research as well as the participants. American Electric Power purchased credits as part of its corporate stewardship activities to learn how the program works. As an early adopter, the utility has an advantage when the program begins selling compliance credits. "We will have first rights to any credits that are available," said American Electric Power's Lohner. If nutrient limits are adopted, the company could also have flexibility with the compliance schedule.

Lohner is also interested in the ancillary benefits of nutrient credits. For example, reducing fertilizer use on a farm reduces emissions of nitrous oxide, a greenhouse gas about 300 times more potent than carbon dioxide. EPRI plans to calculate such reductions as part of the pilot program. In addition, ecosystem benefits of credits could potentially be applied to corporate sustainability goals.

The first trades demonstrated that EPRI's trading protocol works. Fox and her team plan to hold another trading auction later this year to gain a better understanding of the market price. EPRI expects to offer 66,000 nitrogen credits and 30,000 phosphorus credits during the pilot phase.

After the pilot trades of stewardship credits are completed, EPRI will hand off management of the program to another entity that will sell compliance credits, which can be applied toward water quality permit limits. While nutrient-related regulatory compliance has yet to be a major consideration for power producers, wastewater treatment facilities in the region are already struggling to meet their permit limits—representing a likely demand for compliance credits. Eventually, the value of these credits is expected to fully cover the costs of farm best management practices, resulting in a self-sustaining trading market.

By providing a field-tested trading protocol, EPRI's pilot program can provide objective, verifiable findings to any regulatory consideration of water quality trading. "All of us want fishable, swimmable, drinkable water," said Michalene Reilly, manager of environmental services at Hoosier Energy, which has been involved in EPRI's program since its inception. "If we can achieve that in a least-cost fashion and still be effective, who would not want to do it?"

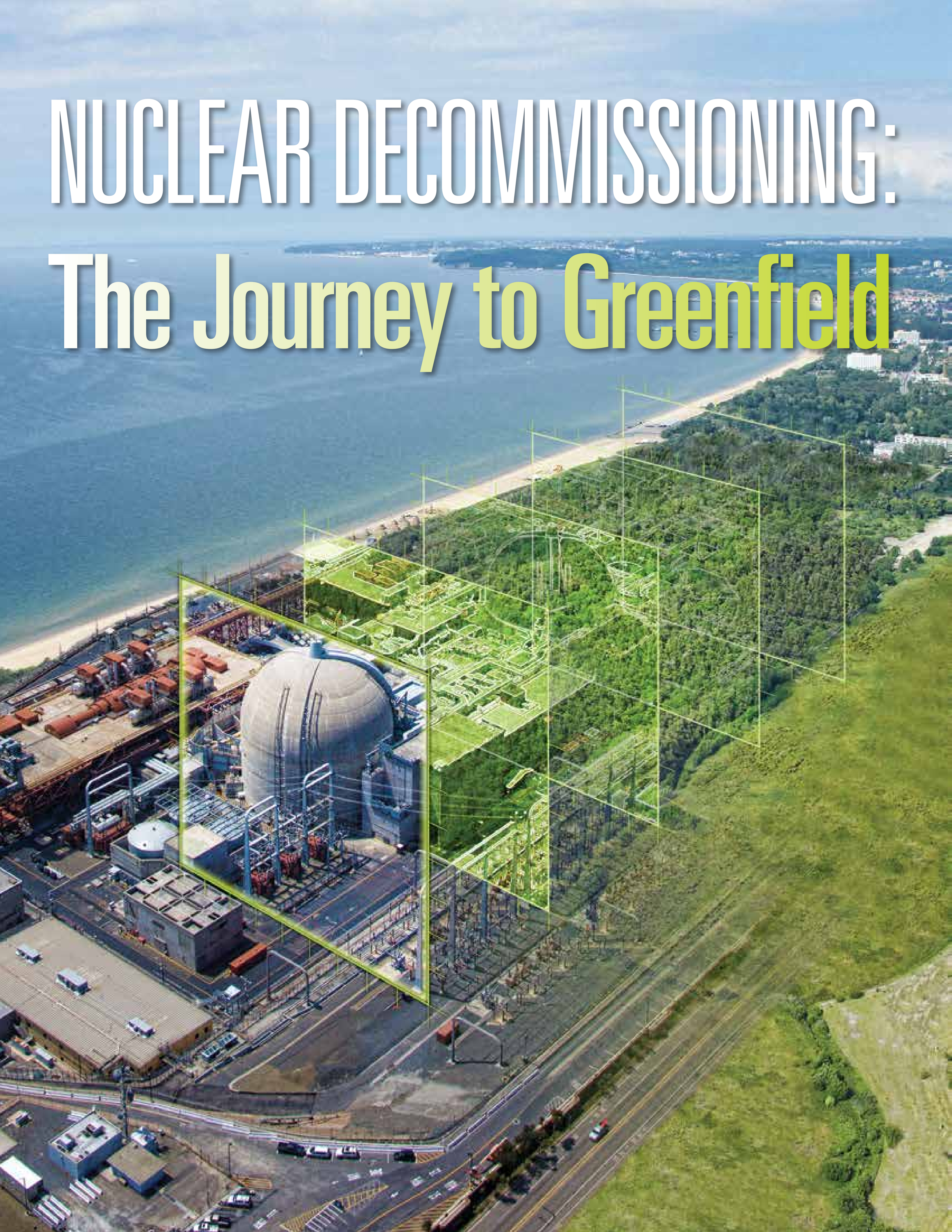
This article was written by Cassandra Willyard. Background information was provided by Jessica Fox, jfox@epri.com, 650.855.2138. Go to wqt.epri.com for more information.

Jessica Fox is a technical executive at EPRI, where she leads efforts on water quality trading, ecosystem services, sustainability, and related work.

YouTube Check out a detailed video of the Ohio River Basin Water Quality Trading project summarizing project operations and on-the-ground agricultural conservation practices. https://www.youtube.com/watch?v=woqkP9c0Dlg

NUCLEAR DECOMMISSIONING:

The Journey to Greenfield



THE STORY IN BRIEF

A wave of nuclear plant decommissioning is expected over the next 30 years. By compiling best practices from global decommissioning projects and conducting R&D on concrete decontamination and robotics, EPRI is helping the industry prepare for the work ahead.

The nuclear industry could see a sharp increase in decommissioning worldwide in coming decades. This global trend, which has already begun, is expected to peak in 2025, when nearly 30 plants could be shut down for decommissioning (see chart below). The increase is, in part, due to the first generation of nuclear plants reaching the end of their lives. Also driving the trend is the 2011 accident at Japan's Fukushima Daiichi nuclear plant, which led to Germany's decision to phase out nuclear power, nuclear program reviews in countries around the world, and questions regarding how many of Japan's nuclear plants may restart.

According to Rick Reid, principal technical leader at EPRI, 46 plants at 35 sites around the world are currently being dismantled. Four plants in the United States have started decommissioning since 2012.

Growing Need for Expertise

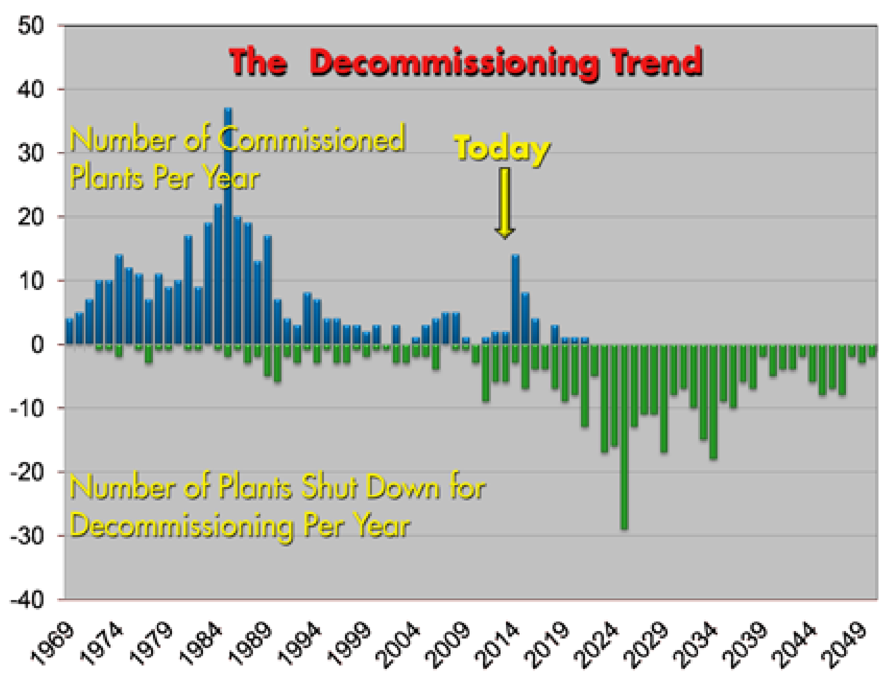
Decommissioning requires years of careful planning, meticulous controls, and layers of radiation protection. Logistical challenges of materials handling are difficult to overstate. Decommissioning can generate more than 100,000 cubic meters of nonradioactive and radioactive waste—enough to fill a football field to a height of about 60 feet—all of which must be characterized by radiation level and processed for disposal. "At the Maine Yankee nuclear plant, more than a million kilograms of contaminated concrete had to be segmented, pulverized, and removed," said Reid.

Despite the exacting nature of the work and the intense focus on safety, "decommissioning is a natural part of the life cycle of any plant, and with nuclear, it has been done successfully," said Reid. To date, 11 commercial power reactors around the world have completed decommissioning, with 8 taken to greenfield conditions and 3 to brownfield conditions. "A number of fair-sized experimental reactors have also been dismantled, bringing the total number of nuclear facilities decommissioned to around 50," said Reid. "There is a really good base of experience to draw on."

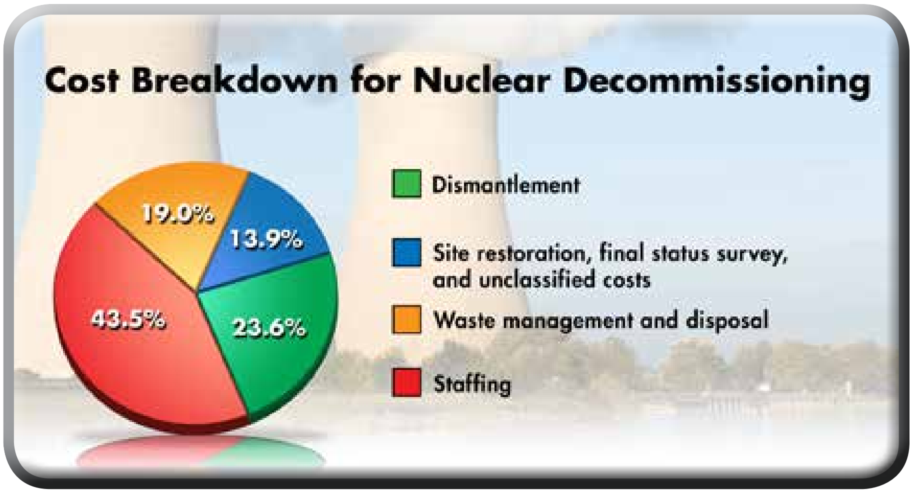
EPRI helps bring that experience to bear. For decades, it has served as an objective technical resource for utilities contemplating or engaging in decommissioning. "The questions we get initially are how to go about planning," said Reid. "Most nuclear utilities have few if any personnel with experience in decommissioning." Reid added that utilities either self-educate or bring in an outside expert. Based on completed projects in the United States, staffing accounts for about 43% of total costs (see chart, p. 16). "Ideally utilities should have a minimum of five years to plan decommissioning," he said.

An early critical decision is which option to pursue—safe storage or prompt dismantlement. Safe storage typically means that the plant will sit idle for three to five decades after fuel is removed. In 2007, PG&E brought in outside expertise to plan and manage decommissioning for its Humboldt Bay Power Plant Unit 3, which had been in safe storage more than 30 years.

Kerry Rod, Humboldt Bay decommissioning manager, points to the importance of technical support. "EPRI brings real benefits to us," said Rod. "They've got good documentation of how previous decommissionings were done, and experienced



Data are for 22 EPRI-member countries only. Data projections beyond 2013 for decommissioned plants are based on the best available information. No data on commissioned plants after 2020 are included due to lack of solid information. The extent of decommissioning will be offset to some extent by new nuclear plant development. In its low-growth scenario, the International Atomic Energy Agency projects 17% growth in world total nuclear power capacity by 2030, to 435 GW, while the high-growth scenario projects 94% growth, to 722 GW.



These data are based on completed decommissioning projects in the United States. Total project costs range from $400 million to $850 million (2008 dollars).

staff. When we run into surprises, we pick up the phone and give them a call." For example, the PG&E team asked EPRI for technical assistance on how to filter out the radioactivity in the plant's reactor vessel after the unit was flooded with water. PG&E started full-scale decommissioning of Humboldt Bay Unit 3 in 2009 and expects to finish by 2019.

Motivations for Safe Storage and Prompt Dismantlement

The decision to store or dismantle rests primarily on economics, radiation concerns, public acceptance, and government policy.

With safe storage, worker exposure is reduced as a result of radioactive decay over time. Beta and gamma radiation fall sharply over 30–50 years, shifting protection concerns to longer life materials known as *transuranics*, which emit alpha radiation. Alpha radiation can be stopped by a piece of paper—but if a source enters the body, biological consequences are long term. Safe storage has lower waste disposal costs than prompt dismantlement because of the available time for radioactive decay. It also offers access to breakthroughs in robotics and other fields that may emerge. Disadvantages are loss of knowledgeable staff and plant operations history as well as changes in policy and public support over time.

With prompt dismantlement, decommissioning teams have access to knowledgeable staff, plant equipment, and supporting infrastructure still in place. Other advantages are the return of valuable land to the economy, reduced long-term liability for the utility, and the public perception of productive action. Disadvantages include higher dose gamma radiation exposure for workers and the volume of high- and mid-level radioactive waste to be removed and transported to a disposal site.

The United States and Canada are trending toward safe storage, while Europe is trending toward prompt dismantlement. "This is certainly the case in Germany, France, and Spain," said Reid. "In the U.K. they have a hybrid approach—to do substantial dismantlement to reduce the scale of future decommissioning, then let it sit for 50 years." Italy recently reversed its direction. "It shut down all its nuclear plants after Chernobyl and put them in safe storage, but after Fukushima, the government is now demanding immediate dismantlement," he said.

With both options, the U.S. Nuclear Regulatory Commission (NRC) requires radiation exposure at the site after decommissioning to be 25 mrem per year or less. Similar dose-based limits apply or are under development elsewhere. For context, average natural background levels in the United States are about 300 mrem per year.

A site must be returned either to greenfield or brownfield conditions. Greenfield conditions reflect the scenario of a *resident farmer*—a globally accepted industry term implying that people can live on the site full time and get all of their food and water from the land. Under brownfield conditions, some plant structures remain standing, and industrial or commercial operations occur on-site. Reid expects most plants worldwide to opt for greenfield because it offers more flexibility in near-term site use and is viewed more favorably by the public.

Humboldt Bay: A Case of Creative Engineering

Humboldt Bay's relatively compact site contains a nuclear power plant, two 1950s-era steam fossil fuel–powered units, and two distillate-fueled Mobile Emergency Power Plants—all of which had to be decommissioned at the same time. Concurrent with decommissioning, PG&E is building a new gas-fired power plant and upgrading the switchyard.

The reactor vessel is underground, surrounded by a reinforced concrete structure 80 feet below sea level. Excavating the structure will require creative engineering. PG&E's Rod said that a 170-foot-deep, 700-foot-long slurry wall will be constructed around the plant to minimize groundwater infiltration. Inside the slurry wall, a soil wall with reinforcement beams will be installed around the reactor vessel structure. "Then we'll pump the water out and begin to excavate the structure," said Rod, adding that the scope of work was recently approved by the California Public Utilities Commission.

All work to date has been completed in-house at PG&E, including cutting the reactor vessel into smaller pieces. After all plant systems are removed this year, Chicago Bridge & Iron Company will become prime contractor on the civil works, which includes removing the entire concrete structure, remediating the intake and discharge canals, and restoring the site.

Learning from others and sharing experiences are part of the decommissioning culture in the nuclear industry. "We had good interaction with the people who went through the bow-wave of decommissioning in the 1990s," said Rod. From Michigan's Big Rock Point, which closed in 1997, Rod brought in the decommissioning manager, who debriefed his team on strategy and lessons. Rod hosted management from Yankee nuclear plants in New England and spent several days at Rancho Seco, a California plant shut down in 1989.

In that spirit of collegial exchange, utilities from around the world now come to Humboldt Bay. "The international community is very interested in our decommissioning strategy and in particular our alpha contamination control techniques," said Rod. "We've had visitors from Japan, Spain, Russia, France, Taiwan, and Iraq."

EPRI's Role

"EPRI is a conduit to the industry to back-check and evaluate that you are taking the right approach," said Rod. "They will do the research, distill it, and give you a neutral view." Rod explained why such neutrality is so important: "If you go to a company, its recommendations may be a business opportunity. EPRI offers an objective assessment and recommendations that you can balance your own decisions against."

Since its inception 20 years ago, EPRI's Decommissioning Technology Program has provided direct support to most utilities with active decommissioning projects. Work in the United States has included Big Rock Point, Connecticut Yankee, Maine Yankee, Rancho Seco, Humboldt Bay, and San Onofre in California. International work has included Spain and Italy.

For 10 years, EPRI has provided technical and planning assistance to the Spanish agency ENRESA to decommission the José Cabrera plant near Madrid—most recently in projects to cut the plant's concrete bioshield, reactor vessel, and reactor internal structures into smaller pieces. With EPRI's help, ENRESA completed the work on the reactor internal structures in about one year—well below the typical 18 months or longer.

EPRI's Experience Summary Reports provide information on these and other decommissioning projects, spanning the process from planning to site remediation.

Strategic Technology Projects

The technology development side of EPRI's decommissioning program focuses on problem areas that Reid characterizes as "more risky, more dose-intensive, or significantly affecting the schedule." Two key focus areas are concrete decontamination and robotics.

Much of a plant's mass is reinforced concrete. Because it is porous and has cracks, radioactive contamination can penetrate deeply. "You can't simply wipe the concrete off as you can with a metal surface," said Reid. "In decommissioning projects many years ago, people were trying to remove a half-inch or inch of the surface, but they found that more activity had migrated deeper into the concrete." As such, concrete decontamination is slow, laborious, and involves a huge amount of material.

EPRI is reviewing available technologies to characterize contamination of concrete structures before and after demolition. It is also assessing chemical and mechanical techniques to decontaminate surfaces and alternative approaches for demolished concrete. One decontamination technology under development uses lasers or liquid nitrogen applied by remotely operated systems.

Robotics and systems automation offer promise to reduce costs and radiation exposure, improve worker safety, and enhance scheduling. "Decommissioning requires a lot of surveying of surfaces around the site, including buildings, segmented slabs, and equipment," said Reid. "This repetitious, time-intensive work is perfect for automation or robotics."

Taking into consideration substantial recent improvements in robotic engineering, control systems, and computer capability, EPRI is identifying tasks for which robotics and automation can make the greatest contribution, including time and labor-intensive tasks and those in high-dose areas. For example, EPRI is developing a system that can wirelessly transfer site radiological data through a cloud server, conduct data analysis, and prepare compliance reports for regulators.

These and other technologies will help the nuclear industry prepare for what promises to be a big task ahead as the decommissioning wave rises.

The Connecticut Yankee nuclear plant before and after decommissioning

This article was written by Brent Barker. Background information was provided by Rick Reid, rreid@epri.com, 704.595.2770.

Rick Reid is a principal technical leader at EPRI, where his research focuses on nuclear plant water chemistry control and decommissioning technologies. Before joining EPRI, Reid worked in the Nuclear Sector at Westinghouse Electric Company as a fellow engineer in the Chemistry Diagnostics and Materials Engineering group. He holds BS degrees in chemistry and mathematics from Charleston Southern University and a PhD in chemistry from Virginia Polytechnic Institute.

R&D Quick Hits

First Look at EMFs from EV Charging

Electric and magnetic fields (EMFs) are present whenever and wherever electricity is generated, transmitted, and used. Limits on EMF exposures are in place to protect human health, and EPRI has a substantial body of research measuring these fields and assessing human health effects. EPRI's latest EMF research revealed that exposures during electric vehicle (EV) charging are well below recommended limits for the general public. Conducted at Southern California Edison's Electric Vehicle Test Center, the study represents the first systematic evaluation of these fields in EV charging.

Measurements were taken at 12 positions inside and outside three EVs—Ford Focus, Toyota RAV4, and Nissan Leaf—and at six positions near the charging systems. Five charging methods were assessed: three conventional power sources providing AC power to chargers in the vehicles, and two fast chargers delivering DC power directly to the vehicle batteries.

The highest electric field measurement was just 12% of the human exposure limit specified in the IEEE standard, while the greatest magnetic field measurement was 0.5% of IEEE's recommended limit. To download the report, go to www.epri.com and enter product ID 3002001128 in Search.

Plants vs. Plants: Water Consumption Estimates Draw Sharp Contrasts Between Power Production and Agriculture

Growing constraints on water availability represent a major challenge for electric power industry operations. To help inform decisions on how to address these constraints, EPRI developed national estimates of water consumption for major sectors of the United States economy, including thermoelectric, agricultural, and municipal. *Consumption* is the amount of water used by a sector and not returned to its original source. *Withdrawal* accounts for that portion removed from a watershed, some or most of which may be returned to the source. Consumption occurs when water evaporates to the atmosphere, is taken up by crops, or is incorporated into manufactured products.

While thermoelectric power plants account for 41% of water withdrawal in the United States, they account for only 5% of national freshwater consumption. Plants of another kind (think irrigated agriculture) account for 37% of water withdrawal but 60% of consumption.

Previous research on national water use focused largely on withdrawal, not consumption. EPRI's report represents the first national water consumption calculations since a 1995 U.S. Geological Survey study. To download the report, go to www.epri.com and enter product ID 3002001154 in Search.

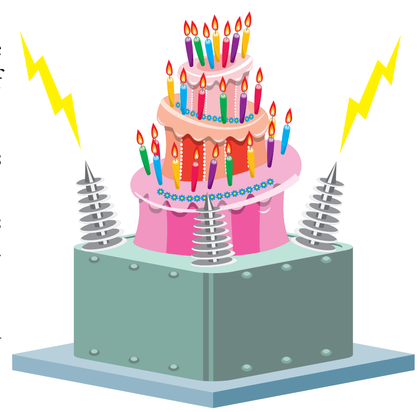
Survey Says: AMI Marches On

A recent EPRI survey of electric utilities revealed that the most common uses of advanced metering infrastructure (AMI) today deal with metering and billing applications. AMI allows for communication between utilities and customers through a combination of smart meters, communications networks, and data management software.

The 27 utilities surveyed worldwide represented more than 50 million meters deployed between the late 1990s and 2013. The most frequently piloted AMI applications include outage notification, power quality monitoring, conservation voltage reduction support, and distribution asset load monitoring. The top planned applications include rolling blackouts, real-time pricing, characterization of customers' grid connection, electric vehicle management, and tariff design.

EPRI plans to repeat this survey in 2014 and 2015 to track AMI trends and identify new applications in use. To download the report, go to www.epri.com and enter product ID 3002001077 in Search.

Transformers Growing Old More Gracefully Than Expected?



Preliminary results of an EPRI study indicate that failure rates of power transformers increase more slowly with age than previously speculated. The finding comes from statistical analyses of an industry-wide database of transformer performance under development at EPRI since 2006.

With records on 40,000 transformers, EPRI's database is the largest of its kind. It offers insights on failure rates, the causes of failure, and the number of transformers in different age groups. By characterizing the transformer aging process, the current study and future database analyses can help utility managers make informed decisions regarding maintenance, repair, and replacement—improving reliability and return on investment.

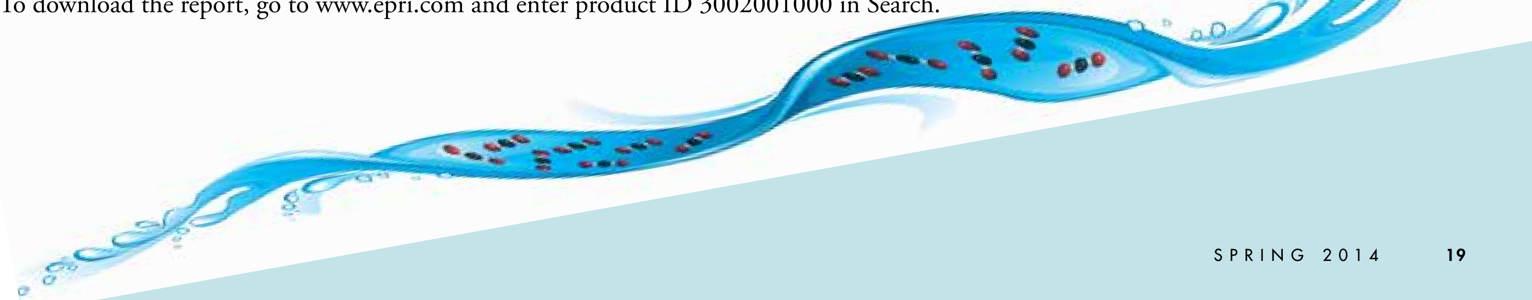
EPRI will continue to add data to the database and improve analysis techniques. To download the report, go to www.epri.com and enter product ID 3002000805 in Search.

Groundwater Impacts of Carbon Capture and Storage: A Deep Dive

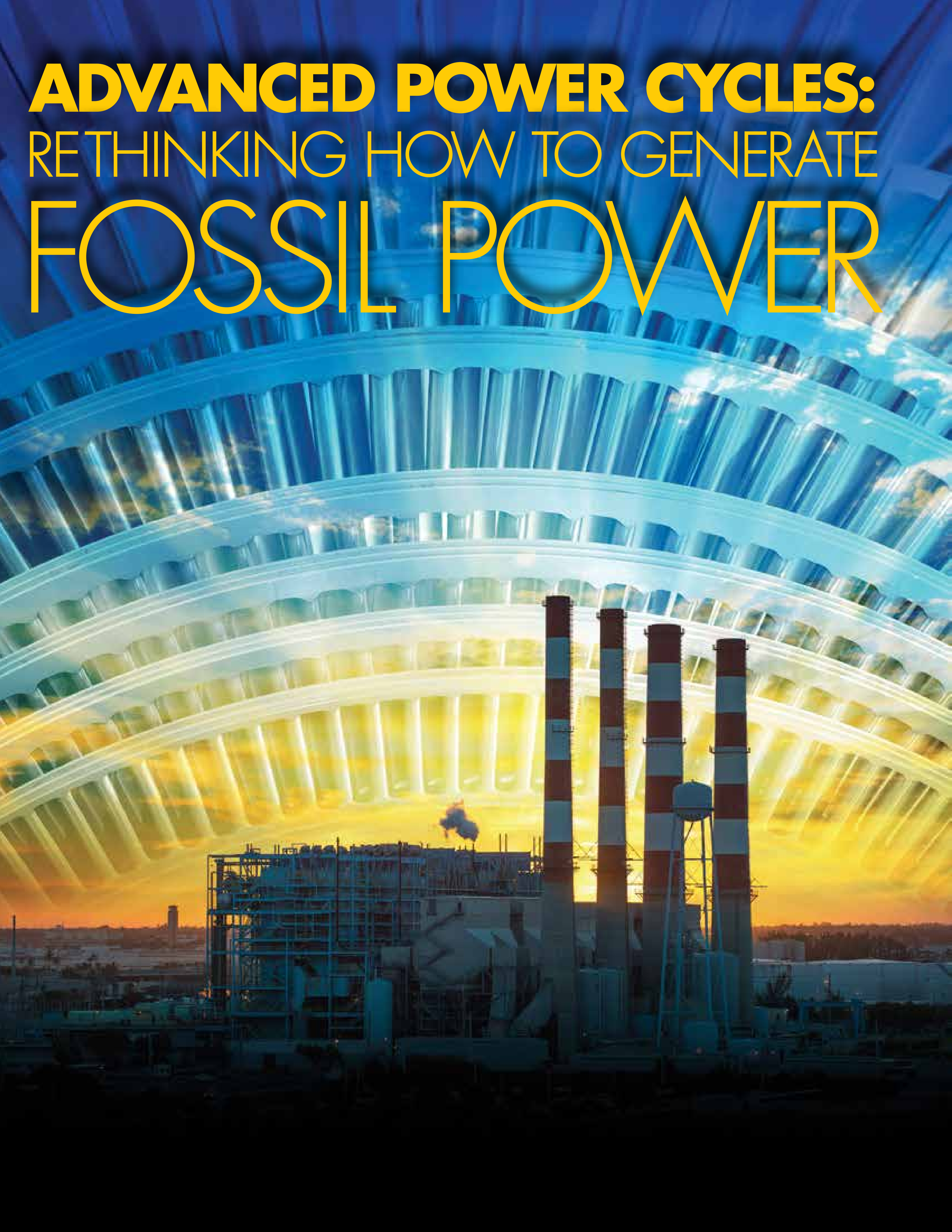
An EPRI study reports valuable insights on the potential impacts of CO_2 capture and storage on groundwater quality. Electric utilities are considering technologies that separate CO_2 from flue gases of fossil fuel power plants and inject it into porous rocks deep underground as one way to reduce greenhouse gas emissions. While the risk of CO_2 leaking from a permitted storage site is low, many stakeholders agree that the possible effects of such an event warrant further study.

In the four-year study, EPRI injected groundwater containing dissolved CO_2 into a sandy aquifer at a depth of about 165 feet for five months and then collected and analyzed groundwater samples. Researchers found that CO_2 causes groundwater to become more acidic, mobilizing naturally occurring metals and ions in aquifer sediments—which in turn releases them into the groundwater and increases their concentration. EPRI characterized concentration trends for a range of metals and developed models to predict their fate. None of the measured metal concentrations exceeded enforceable limits under federal primary drinking water standards.

The findings can inform the future selection of CO_2 storage sites and strategies for remediating CO_2-impacted groundwater. To download the report, go to www.epri.com and enter product ID 3002001000 in Search.



ADVANCED POWER CYCLES: RETHINKING HOW TO GENERATE FOSSIL POWER



In 1859, Scottish civil engineer, mathematician, and amateur singer William John Macquorn Rankine penned the book *Manual of the Steam Engine and Other Prime Movers*, describing a sequence of events to drive a steam engine. The cycle involves pressure and temperature changes in fluid that generate power. Today the Rankine cycle remains the standard process for coal-fired power generation and is part of natural-gas–combined-cycle plants. These technologies reliably supply much of the world's electric power and will continue to do so for the foreseeable future.

Yet, the cycle's impressive longevity may reach its limits. In recent decades, the drive to improve efficiency and lower emissions in coal and natural gas power generation has resulted in mainly incremental improvements in these technologies. Further improvements are bounded by physics—the properties of the working fluids and the ability of available metals to withstand higher temperatures and pressures. With tightening emissions regulations and increasing cost pressures, there's a need to develop completely novel power cycles for transformational gains.

Researchers are investigating materials that can withstand the high steam temperatures and pressures in advanced ultra-supercritical (A-USC) plants that offer a more efficient version of the Rankine cycle. Beyond this, the industry has few strategic options to further advance coal-fired power generation based on the Rankine cycle.

A daunting challenge for conventional generation technologies is the prospect of mandates for dramatic carbon dioxide (CO_2) emissions reductions. Although efficiency improvements can achieve some reductions, any deep emissions reductions would require major design changes.

"What makes the requirement to reduce CO_2 so significant is that the production of CO_2 is a fundamental part of fossil-fuel-fired power generation," said David Thimsen, EPRI principal technical leader. "The energy comes from making CO_2."

THE STORY IN BRIEF

Conventional coal- and natural-gas-fired power generation technologies are approaching their efficiency limits. With growing pressure to reduce costs and emissions, EPRI is investigating designs of advanced—and largely untried—power cycles that show promise of higher capacity, lower costs, and improved control of carbon dioxide and other pollutant emissions.

Thimsen adds that capturing the CO_2 in pure form with available fossil technologies will significantly reduce efficiency.

A Clean Slate

There's a growing awareness in the electric power industry that technologies enabling transformational—rather than incremental—gains are necessary to keep fossil fuel generation viable.

"If the past two decades have taught us anything, it's that constraints, particularly on fossil fuel emissions, are going to keep getting tighter," said Nick Irvin, program manager, Southern Company Research and Environmental Affairs. "We have to step back and look at some bold efforts to get beyond these constraints."

Matt Usher, director of new technology development and policy support for AEP Generation, agrees. "We're going to require technologies that shift the electricity generation paradigm. It could mean starting from a clean slate—distancing ourselves from traditional cycles and looking at innovative cycles that can deliver energy in a manner that is more efficient and reduces overall carbon emissions."

In 2013, EPRI began a program to systematically investigate innovative fossil generation technologies under development worldwide and identify and advance the most promising ones. The program is focusing on cycles that can power units larger than 50 megawatts and that have potential for commercial availability in 5–20 years. Technologies under consideration have the potential to improve capacity, lower capital costs, provide CO_2 capture, and offer zero or near-zero emissions of other pollutants.

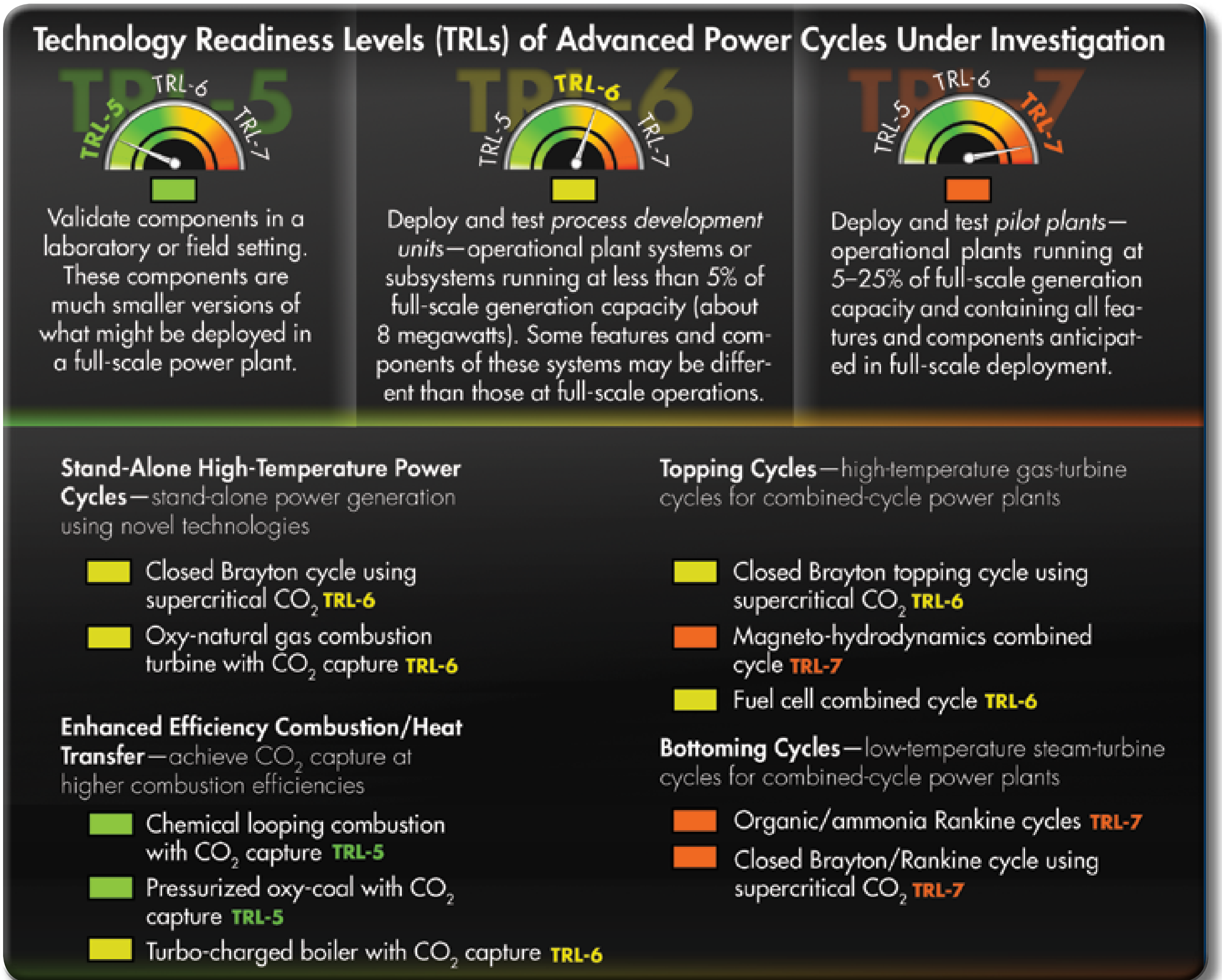
Thimsen explains why this research is needed, even during the current era of low load growth. "Over the next 10–15 years, it's estimated that 20% of U.S. coal-fired plants will be retired," he said. "Even with flat load growth, that capacity will have to be replaced. If we get any economic growth, there will be a need for plants to meet the increased load."

Southern Company's Irvin says that "this is exactly the right time" for long-range R&D, adding, "There's not a lot of near-term demand on these technologies, so we can make long-term choices that get us better end results without the pressure of near-term deliverables."

EPRI is investigating 10 coal- and natural-gas-fired technologies (see box, p. 22) in several categories, including the following:

- Stand-alone power cycles
- Both sides of combined-cycle plants: higher temperature, gas-turbine-side topping cycles, and lower temperature steam-turbine-side bottoming cycles
- Technologies that provide more efficient energy conversion with CO_2 capture

More technologies may be added as the program proceeds.



With respect to natural gas technologies, researchers are assessing the integration of CO_2 capture as well as the potential to achieve efficiencies greater than those of natural-gas–combined-cycle plants or comparable efficiencies at lower capital cost. They're also looking at whether natural gas technologies may be applied to coal-fired power plants after basic technology issues are worked out.

"These new technologies will require significant testing, scale-up, and demonstration to assure the industry of their feasibility and long-term commercial reliability," said Thimsen. "Advancing the technologies to full-scale commercial deployment will take considerable time and investment from utilities, suppliers, and government agencies."

The program's focus is twofold: First, gain a better understanding of the technologies and their developers through reviews, engineering analyses, and feasibility and readiness assessments. Second, use these analyses to identify the most promising technologies, outline research roadmaps to advance them, and secure funding for field demonstrations.

Closed Brayton Cycle

One technology under consideration is not new. The Brayton cycle was developed in the nineteenth century and has long been used for internal combustion engines. "Open" Brayton cycles—those that exhaust gases to the atmosphere—are commonly deployed today for electric power production as gas turbines.

EPRI is investigating a "closed" Brayton power cycle in which the gas leaving the turbine is cooled and sent back to the compressor inlet, with no exhaust to the atmosphere. At the compressor inlet, the working fluid (CO_2) is in a supercritical state—at a pressure and temperature with no distinct liquid and gas phases. Because supercritical CO_2 (SCO_2) is very dense under certain conditions, less power is required for compression relative to a traditional combustion turbine.

Compared to Rankine cycles, closed Brayton cycles with SCO_2 have the potential for greater efficiency and reduced machinery size and cost. Deployment at

Echogen prototype 10 MW closed Brayton cycle process skid. Used with permission from Echogen Power Systems, LLC (2014)

full scale will require components not commonly in service today, including large heat exchangers called *recuperators* that recover and reuse heat, special turbines, and SCO_2 heaters. Nevertheless, design and fabrication of these components are achievable with existing engineering expertise.

In a 2013 study, EPRI compared the performance of three closed SCO_2 Brayton power cycles with steam Rankine power cycles under similar turbine inlet temperatures and pressures. It found that the thermal efficiency of the Brayton cycles exceeded that of the Rankine cycles by as much as 4 percentage points—equivalent to a 10% reduction in fuel use.

Another EPRI study comparing a closed Brayton topping cycle to an A-USC Rankine cycle for repowering an existing 500-megawatt steam-electric power plant revealed that the Brayton cycle yielded a 4.4% increase in net efficiency, while the Rankine cycle yielded a 2.7% efficiency increase.

To date, three small (~200 kilowatt) closed Brayton cycle power plants have been deployed. A private developer has built a 10-megawatt prototype for generating power from turbine exhaust heat; another developer is planning a 20-megawatt plant in 2015. In addition, the U.S. Department of Energy (DOE) is considering a project to deploy a 10-megawatt plant as well as a program to support larger plants.

Going forward, EPRI will organize participation in one or more of these pilots as supplemental projects and complete conceptual designs of closed Brayton cycles to optimize efficiency for both coal- and natural-gas-fired plants.

Pressurized Oxy-Combustion with CO_2 Capture

Another technology under investigation is oxy-combustion, a process that separates oxygen from air and combines it with recycled flue gas so that combustion occurs in the presence of oxygen and CO_2. By producing a CO_2-rich flue gas, the process facilitates purification and compression of CO_2 for transport and storage. Previous studies have concluded that oxy-combustion with CO_2 capture could be cost-competitive with conventional air-fired coal plants incorporating post-combustion CO_2 capture.

Pressurizing oxy-combustion can increase plant efficiency by reducing the steam generator's size and cost, increasing boiler efficiency, and reducing auxiliary power consumption. DOE has funded five engineering/design studies of pressurized oxy-combustion and selected two developers for field work, stipulating a minimum target of 90% CO_2 capture. EPRI engineers are participating in these projects.

Looking to the Future

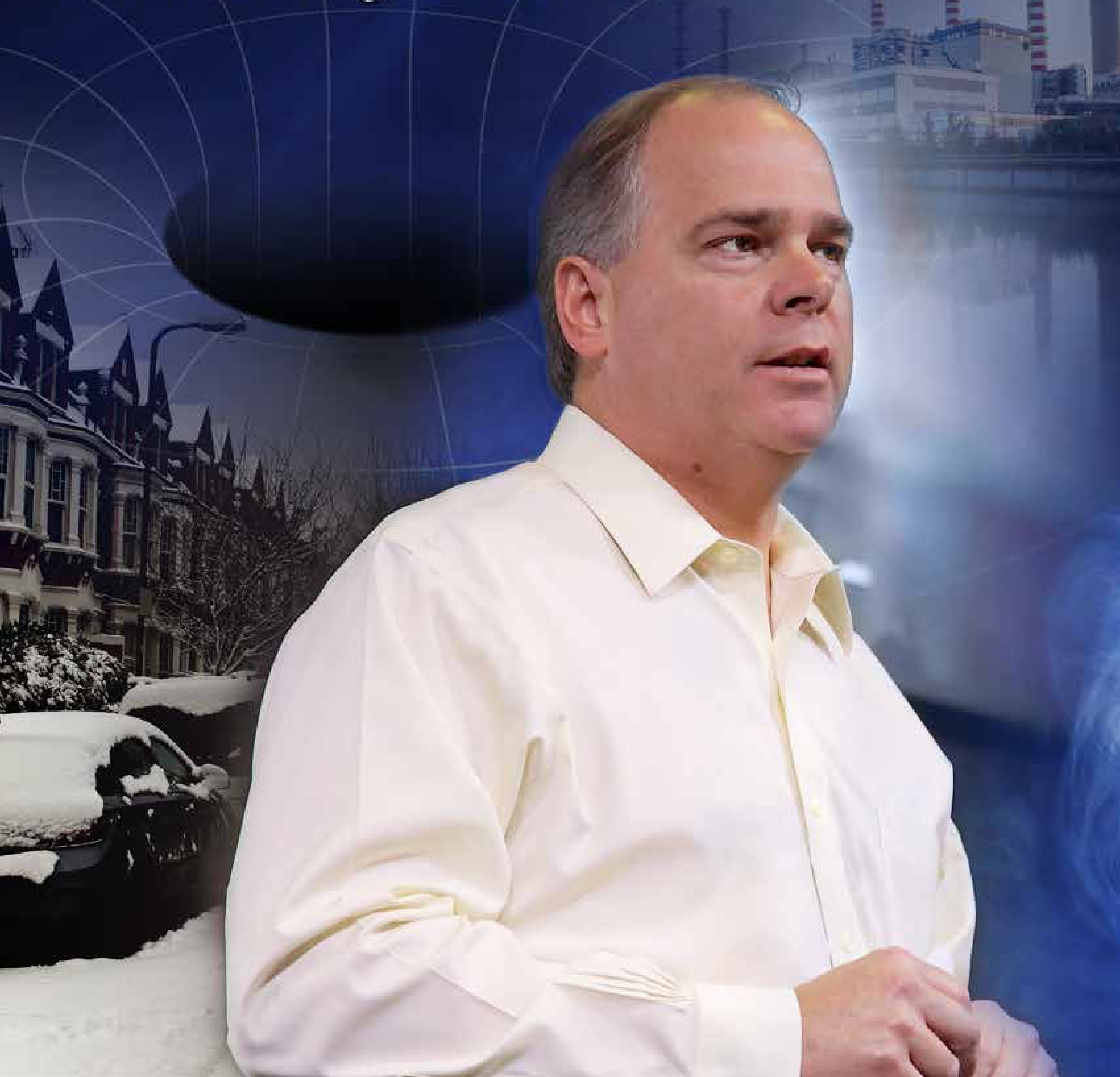
As part of its research on advanced power cycles, EPRI plans to build an online database to document advances in the technologies. Each year, EPRI will review one technology through in-depth engineering and economic analyses, performance assessments, and levelized cost of electricity estimates. A version of the closed Brayton power cycle using coal gasification as the fuel source will be the subject of this "deep dive" in 2014.

This article was written by Jonas Weisel. Background information was provided by David Thimsen, dthimsen@epri.com, 651.766.8826.

David Thimsen is a principal technical leader in EPRI's Fossil Fleet for Tomorrow program. He worked closely with EPRI in the late 1980s and 1990s to facilitate the field deployment of fluidized-bed combustion technology for utility-scale power generation. More recently, Thimsen has managed small generator installation projects for the Distributed Resources program at EPRI as well as advanced coal-fired power generation projects and field deployment of post-combustion CO_2 capture.

Back to the Basics of Baseload

Looking Back at the Polar Vortex and Looking Ahead



Nick Akins is chairman, president, and chief executive officer of American Electric Power and is a member and former chairman of the EPRI Board of Directors. In this interview, he discusses how strains on U.S. power systems during the past winter underscore the need for long-term coal and nuclear baseload generation.

EJ: To what extent did this past winter's polar vortex pattern strain U.S. power systems? And what, in your view, caused such strain?

Akins: It put considerable strain on the system. There were voltage reductions and periods when PJM [a regional transmission organization in the Eastern United States] was very close to having to shed load. That's a concern. We've continually taken margin out of the system by depending on resources that may or may not be there when we need them. This is due to the transformation from coal to natural gas, and increased dependence on intermittent supplies and demand-side management for reserves. Extreme weather really tests the system. As a former system operator, I've been through extreme cold weather for extended periods, with forced outage rates going up because of equipment failures, freezing coal piles and natural gas taps, and pipeline pressure not accommodating the load requirements, as well as the system itself taxed with a heavy load. Clearly, the recent polar vortex events were a calling card of what's to come if we do not get the resource mix right.

EJ: You have pointed to the difficult choice between committing natural gas resources to generating electricity or heating homes. What happened to force that choice?

Akins: Typically, local natural gas distribution companies have first call on the resources because the law provides that natural gas is used for consumers before power plants. That leaves the natural gas generation in a more tenuous position. The natural gas industry relies on electric power to provide the required pressure in the pipelines. And now, the electric industry relies on natural gas to fuel many of its generators. The two industries are dependent on one another, and without appropriate coordination, neither will be able to serve its customers reliably. If we're going to depend upon natural gas in a substantial way as a fuel for the generation fleet, then we're going to have to invoke better coordination between the two industries.

EJ: What role did coal play during the winter?

Akins: It has been fairly well publicized that 89% of AEP's coal fleet that is due to retire in mid-2015 was called upon and operated during January. In that month, the deposition capacity factor [percentage of time the plants were utilized to meet load requirements] for the retiring units that ran was approximately 51%. That's not just a one-off type of activity for these units. They were being utilized substantially during this period. What happens when those units retire in mid-2015, and we have a really hot summer or a very cold winter? What's going to provide that energy? That's a question that needs to be answered.

EJ: Have you talked with your peers about their companies' experience during the polar vortex? Any interesting takeaways?

Akins: People on the coal side and the nuclear side are very concerned about the market signals for steel-in-the-ground assets. Not only is the market not providing enough revenues to pay the long-term costs of keeping this baseload capacity online, but there's concern about further retirements because of the ongoing lack of revenue support for that generation.

Second, the energy market reached $1800 per megawatt hour (MWh), which reflects the shortage of available capacity to meet the energy requirements of the system. If generation is not available, PJM calls on demand response. Those needing energy at that time were in effect paying $1800 per MWh to demand-side management providers. Most demand-management providers have no obligation to provide any capacity during winter months and minimal penalties if they don't deliver reductions, yet they get paid $1800 per MWh. There's a significant disconnect between the value and risk proposition of operating a generating unit and providing demand management, and that needs to be reconciled.

EJ: Could cold winters and greater reliance on gas-fired plants point us to new market dynamics?

Akins: I think it increases the volatility of energy markets, and unregulated jurisdictions have the challenge of mitigating that volatility. In the aftermath of the polar vortex, utility commissions are becoming concerned about the prices that are being passed on from different retail energy

"People on the coal side and the nuclear side are very concerned about the market signals for steel-in-the-ground assets. Not only is the market not providing enough revenues to pay the long-term costs of keeping this baseload capacity online, but there's concern about further retirements because of the ongoing lack of revenue support for that generation."

providers—and that's because they have no recourse when market conditions result in exorbitant energy prices. Retail providers must be able to pass on the costs or price the risk into the product they provide—otherwise, they go bankrupt. There's a new set of dynamics when you take more coal and nuclear generation out of the mix and become more dependent on natural gas. Natural gas volatility is going to increase, and that's going to be a challenge for the consumer. You have to argue for a balanced energy portfolio that mitigates risk. You can't take long-term baseload generation out of the portfolio mix without increasing the price, volatility, and reliability risks for consumers.

Natural gas prices currently are low, implying a low-cost energy source for the future. But natural gas markets historically have been volatile. And while we now appear to have a wealth of shale gas resources, the reality is that many of those shale plays have barely been tapped. Recently, the EPA has begun talking about the environmental impacts of shale gas wastewater, and investigations into the relationship of horizontal fracking and earthquakes are underway. The natural gas industry is exploring export opportunities that could be very lucrative for them, but not bring about the low domestic prices American consumers are assuming. These all may turn out to be manageable issues. But low-cost natural gas far into the future is not a sure bet.

EJ: You've said that there are not the right pricing signals to support existing coal and nuclear plants. What's needed?

Akins: If you look at PJM capacity auctions over time, the prices are too volatile to support new construction and maintain the current fleet of nuclear and coal generation. That's a big problem. In PJM's Rest of Market [parts of PJM territory that are outside congested zones], capacity clearing prices have spanned from $174 to $16 per megawatt-day. It's more volatile than the stock market—especially for a capacity product that people depend upon to run the economy. That highly volatile capacity market makes the energy market even more volatile, because existing coal- and nuclear-fueled capacity isn't receiving the appropriate price signals to continue operation and may not be there when needed. That has to be resolved. What's not available in markets right now is a long-term capacity product. The PJM capacity market is a one-year product with a three-year advance notice. This is not a long enough time commitment to justify construction of steel-in-the-ground plants. There needs to be a long-term product—at least five years and preferably longer—to build new capacity.

EJ: What structural changes are needed in electricity markets to stimulate the construction of baseload generation, and when are they needed?

Akins: You need capacity markets that are consistent among the regional transmission organizations. Different parties can arbitrage between the rules of the different regional capacity markets, but if you can't maintain steel-in-the-ground generation within a region, you'll be depending on imports and/or suboptimal generating products. You have to think about the physical grid first and not focus solely on the development of a national energy market. Like politics, everything in the electricity industry is local because of the reliability implications of voltage and VAR support to keep the grid running.

In cold weather situations, for example, you will have a more reliable system if you have readily available nuclear, coal, and natural gas generating units, so you're not entirely dependent on natural gas pipeline transportation for electricity production. There should be some mechanism to ensure that baseload generation is available to provide foundational support for the grid, and there should be a revenue stream that supports the baseload generation within a region. Then the rest of the generation resources can come into play. You can't have all your reserves hanging on resources that may or may not be there and perhaps don't even have the obligation to be available at all times.

"Additionally, you have to look at renewables as mainly an energy product and not a capacity product. The same is true for demand response, although it's more pointed from a time perspective relative to demand."

"A lot of work also needs to be done to address the grid's ability to accommodate multiple types of resources, whether they're intermittent resources, baseload resources, or distributed resources. The grid has to respond differently and respond much smarter than it has in the past."

EJ: In terms of broad market value and specific services, what do coal and nuclear baseloads provide that natural-gas-fired generation, demand response, and renewables do not?

Akins: Traditional coal and nuclear generating units support 24/7 supply and provide the foundation for the grid. Natural gas can be used as baseload generation, but it's just not as prevalent as coal and nuclear. Coal and nuclear provide stability in supply and in operations. What is critical for grid reliability is to get full capacity benefit for that dependable, 24/7 capacity at all times. With gas-fired generation, you don't have fuel inventories on-site, and you are susceptible to interruption due to pipeline pressure, cold weather, or local distribution companies being allocated gas first. Renewables and demand response are one-off resources. Renewables are intermittent. Demand response currently is not structured so you can call on it and depend on it at any time during the year. The amount of available demand response also is dependent on actual consumer response. There is a growing concern about customer fatigue, if we call on demand response more often in the future.

Additionally, you have to look at renewables as mainly an energy product and not a capacity product. The same is true for demand response, although it's more pointed from a time perspective relative to demand. Virtually all of the demand response that has traditionally cleared the PJM auction can be called on only for a limited amount of hours during the summer and is under no obligation to respond at other times of the year. That has to change. I'd say coal and nuclear are the foundation for the grid, and you build on top of that.

EJ: Looking at regulation: Is there the potential for environmental rules to create holes or gaps in baseload capability, and are regulatory changes needed to support or expedite new baseload capacity?

Akins: Absolutely. There's a distinct risk that we're going to have gaps. The MATS [Mercury and Air Toxics Standards] rule is retiring more generation than anyone envisioned. EPA thought 10 gigawatts would be affected; we said 60 gigawatts. It's turned out that between 60 and 80 gigawatts of coal-fired generation will retire. The grid needs time to respond to this level of change, not only through development of other generating resources, but also development of transmission resources to ensure that we can accommodate the retirements. New generation resources—regardless of their fuel sources—will also require new transmission projects to connect them.

Other pending environment regulations —the water rules, the ash disposal rules, the greenhouse gas rules—will place additional burdens on the coal- and nuclear-fueled generation that is already struggling with market constructs. You could end up accelerating additional retirements of coal- and nuclear-fueled generation at a time when the system can barely manage the current retirements. We need to be sensible about this. Too many times policymakers don't understand how the system actually works—and that really requires education, studies and modeling, thoughtfulness, and time to get it right.

EJ: Any thoughts regarding changes in the regulatory structure to facilitate that?

Akins: The Department of Energy, Federal Energy Regulatory Commission, Environmental Protection Agency, and perhaps even Homeland Security need to get together, focus on grid reliability, and think about what the transition should be. We want to be environmentally responsive, but do it in a reasonable way, given the potential impacts on the reliability of the grid and what it does to our customers and the economy. It's incumbent on those agencies to work together and to seek out the advice of people who know something about operating the system. In the absence of Congressional action, we really need to focus on the agencies working together to get this right.

EJ: Given everything we've discussed, where should R&D focus?

Akins: We have to continue focusing on greenhouse gas capture and use from coal-fueled generation and even natural gas-fueled generation. If the United States is focused on reducing greenhouse gas emissions, then it ought to prioritize funding for full demonstration projects to advance the science. As EPRI knows, bench-scale work is a very different proposition from deploying technology in a full industrial environment.

A lot of work also needs to be done to address the grid's ability to accommodate multiple types of resources, whether they're intermittent resources, baseload resources, or distributed resources. The grid has to respond differently and respond much smarter than it has in the past. The technology around those kinds of real-time adjustments—those are the leading candidates for technology deployment as we define the utility of the future.

Advanced Welding Technology for Nuclear Power Plants Shows Promise in Lab Tests

EPRI has completed successful laboratory tests on a new welding technology that could support decisions by nuclear plant owners to safely extend the life of their assets. Friction stir welding is intended for repairs on aging, highly irradiated plant components that existing welding techniques are unable to handle. EPRI and Oak Ridge National Laboratory (ORNL) are conducting further tests this year to optimize the technology.

Welding Is Essential for Repairing Some Aging Components

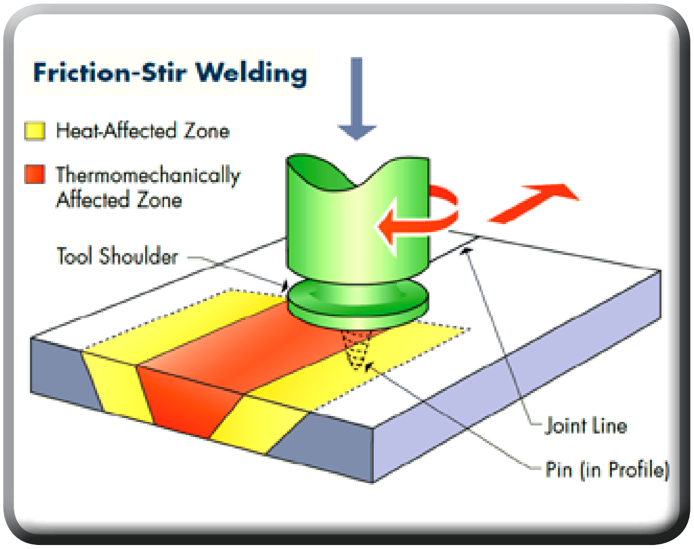
Over time, helium accumulates in nuclear power plant components as a result of radiation exposure, making them increasingly brittle. After about 30 years of operation, helium levels reach a point at which components become susceptible to significant cracking from the heat input from welding and stresses on the material as the weld cools.

As nuclear plant life is extended, the ability to repair critical components in these aging plants may become an important consideration. Friction stir welding shows promise for sealing surface cracks and repairing components without causing cracking. In contrast with most conventional welding processes, friction stir welding involves no melting of parts to join them. Instead, a specially designed tool is pressed against the surfaces to be joined. The tool rotates as it moves along the joint line, creating frictional heating that softens the underlying column of material. The softened material flows around the tool, recrystallizes, and consolidates into a continuous joint. Because recrystallization occurs at temperatures lower than other welding technologies, cracking is avoided.

From Lab Demonstration to Optimization

EPRI is collaborating with ORNL to develop and demonstrate friction stir welding tools and processes. ORNL's specialized "hot cell" facilities enable welding tests of irradiated materials. Through conversations with nuclear industry stakeholders, EPRI is working to ensure that the technology ultimately works in the field.

In 2013, EPRI successfully demonstrated in both air and underwater environments that friction stir welding can seal cracks on test plates made of materials commonly found in reactor pressure vessels—the chambers where nuclear reactions occur. Researchers have also characterized repairs of cracks from manufacturing defects, again with promising results.



Friction stir welding creates two distinct zones in a material. In the heat-affected zone, heat alters the mechanical properties of the material. In the thermomechanically affected zone, both heat and the stirring action of the tool impact the material's properties.

EPRI studies in 2014 will work to validate and optimize the technology at ORNL. In parallel, EPRI and ORNL are irradiating common component materials to induce the high helium levels typical inside reactor pressure vessels after 40 to 70 years of operation. In 2015, they will evaluate the technology's effectiveness on these samples. Results of both studies will help researchers refine welding tools and processes for field demonstrations in reactor pressure vessels.

With its potential for sealing cracks and crack-like material defects on a range of irradiated materials, the technology may allow for greater automation and real-time feedback and control in welding.

For more information, contact Greg Frederick, gfrederick@epri.com, 704.595.2571.

New Research Quantifies Heat-Exposure Risks for Power Industry Workers

A recently launched EPRI investigation is shedding light on an important—yet poorly quantified—health and safety risk for workers in the electric power industry: exposure to heat. Expected to be complete in 2015, the research has already generated valuable insights that can lead to more effective occupational safety guidelines and practices.

Many Risk Factors

EPRI is looking comprehensively at how electric power industry workers can be exposed to heat. Many work near hot machinery, in areas with restricted ventilation, or in regions with high temperature and humidity for part or much of the year. They may also have periods of high, sustained exertion.

Also under investigation is personal protective equipment such as coveralls, helmets, rubber gloves, arc- and flame-resistant clothing, and garments to minimize exposure to hazards. The properties of this clothing—such as insulation, ventilation, and permeability to water vapor—can significantly reduce the rate at which workers dissipate body heat, increasing overall heat exposure.

Such factors put a variety of power industry workers at risk of *heat strain*—a sharp rise in body temperature that can result in fatigue, confusion, and diminished motor function. These symptoms can in turn lead to reduced alertness, impaired decision making, injuries, and productivity loss. Heat strain can occur year-round, indoors or outdoors, and in a range of industry settings.

Occupational guidelines exist to prevent heat strain in industrial workers through work and rest period recommendations. But these guidelines do not address all working conditions, activities, and clothing specific to the power industry. The development of science-based, task-specific guidelines for electric power industry workers requires data on the extent and severity of these workers' exposure to heat—and such data are currently lacking.

Two Related Studies

In 2013, EPRI's Occupational Health and Safety program launched a research initiative with the University of Ottawa to examine and measure how various factors increase heat strain risk in power industry workers. This research will be used to develop guidelines to reduce heat-related illnesses and injuries.

Two related studies are in progress. One is a field assessment of the physical demands of industry work activities. Researchers

A chamber in a University of Ottawa laboratory used for the heat-exposure experiments

are video-recording workers as they perform a range of tasks at several power company sites in North America. To quantify the effects of heat strain, researchers are collecting real-time data on ambient temperature and humidity as well as physiological data such as body temperature and heart rate.

The second study is looking at how commercially available protective clothing affects heat strain. In a laboratory setting with temperature and humidity conditions typical of industry work environments, participants wear various clothing types and perform exercises designed to replicate the physical exertion of industry activities. Researchers collect physiological data—including body temperature, heart rate, and heat loss—and compare them with data from control subjects wearing only shorts, underwear, and socks.

Preliminary results indicate that protective clothing severely restricts the body's ability to dissipate heat. In 2014, investigators will continue to evaluate the influence of additional clothing types on body heat during rest and physical work states.

Measuring heat effects of specific tasks and clothing can inform industry-specific guidelines such as hydration practices, environmental cooling requirements, work and rest schedules, and worker education. It may also help identify clothing designs and materials that provide better ventilation and moisture control. By collecting data on indoor and outdoor conditions in various climatic regions, the field work is expected to help identify those parts of the workforce at higher risk of heat strain. Two preliminary EPRI reports (1023806 and 3002001015) are available.

For more information, contact Chris Melhorn, cmelhorn@epri.com, 865.218.8013.

Acoustic Mouse Prototype to Move Ultrasonic Imaging Technology Closer to Commercial Availability

A recent EPRI study has brought the "acoustic mouse" closer to commercial reality, opening the way for the ultrasonic sensor-in-a-mouse to provide three-dimensional interior images of a broad range of nuclear and fossil plant components. EPRI is testing a prototype this year.

Combining the Advantages of Two Technologies

Power plant operators use ultrasonic testing to detect and characterize components' structural integrity and assess their remaining operational life without causing damage. However, two main categories of ultrasonic inspection currently employed in power plants—one manual, one automated—come with significant drawbacks.

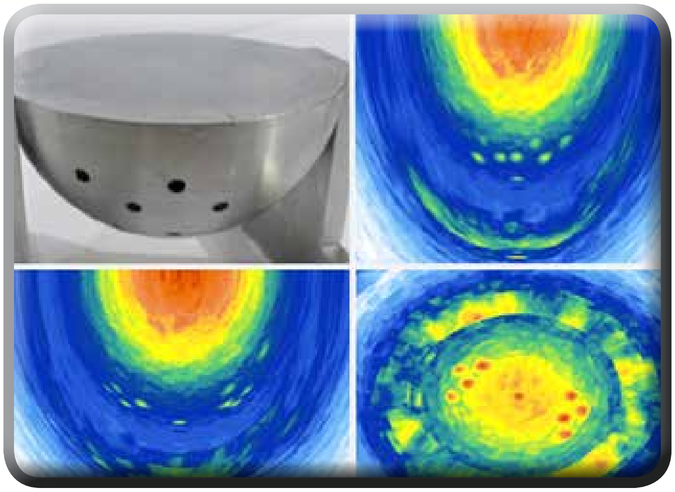
With the manual method, a human operator moves a handheld ultrasonic device across a surface. Although low cost and capable of inspecting broad areas, it does not typically generate computer-encoded images and support quantitative analysis. This can result in false positives, conservative interpretations, and premature or unnecessary maintenance. The automated approach relies on robotic ultrasonic systems to inspect components and deliver computer-encoded three-dimensional images for quantitative flaw assessment and better decision making. However, these systems are significantly more expensive, require time-consuming setup, may experience mechanical breakdowns, and cannot access many components and configurations.

EPRI's acoustic mouse technology combines the advantages of the manual and automatic devices while minimizing the disadvantages. The handheld sensor has the potential to inspect limited-access components and complex configurations while generating computer-encoded images at high precision and low cost.

Evaluation of Sparse-Array Technology

An ultrasonic device, often called a *transducer*, sends high-frequency sound waves into an object. The waves reflected from structures inside the object are received by the transducer as echoes. The device translates these echoes to construct an image of the object's interior. The work of sending and sensing these sound waves is done by one or more elements inside the transducer.

EPRI's breakthrough involved the evaluation of "sparse-array" handheld ultrasonic technology for generating accurate three-dimensional images. Using fewer, more widely spaced elements than conventional ultrasonic devices, a sparse-array transducer relies on fewer data—greatly reducing the time and expense for data processing, software, and hardware.



Hemispherical bowl with holes (top left) and three ultrasonic images from a sparse-array transducer showing different planes within the bowl

EPRI investigated the extent to which the number of transducer elements can be reduced—and how the elements can be configured—while still yielding quality images. Researchers tested the ability of several sparse-array transducer configurations to build images of hemispheric aluminum structures with holes drilled in them at various orientations. They found that the devices can image from a single stationary position with good resolution and that the number of elements could be decreased by at least 50% without degrading image quality.

EPRI also studied how the positioning of the elements in a sparse-array transducer affects ultrasonic images, observing that configuring the elements in random patterns reduced undesirable noise in images. This finding is critical to designing an effective prototype.

Moving Toward Field Demonstration

In 2014, EPRI plans to test different transducers, sensor positions, and movements—such as a sweep in one or more directions—to generate images of components. EPRI will develop an acoustic mouse prototype based on the sparse-array technology and test it on full-size mockups of power plant components. Inspection system manufacturers are expected to begin integrating EPRI's innovations into commercial products for field demonstration and testing of diverse power plant components in 2015.

For more information, contact Mark Dennis, mdennis@epri.com, 704.595.2648.

New Tool Simplifies Water Planning

At a point where water is emerging as a crucial factor in siting and operating electric power generation, EPRI completed two prototype applications of software that companies can use to craft sustainable water management plans. "Water Prism" equips companies with the ability to review their water uses along with competing uses within the community and to evaluate various water management approaches. By providing a clear, basin-wide picture of how water-related risks may increase in the future, the software supports collaborative planning and informed decisions about the best path forward. The prototype applications in 2013 use watershed data from the Muskingum River Basin in Ohio and the Green River Basin in Kentucky.

Supporting Informed Decisions

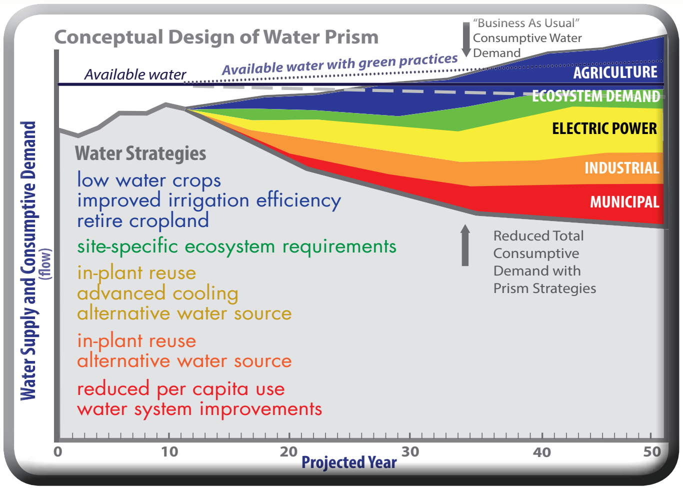
EPRI senior technical executive Robert Goldstein explains the tool's relevance in today's business environment. "Thermoelectric power plants face growing challenges to obtain water needed for operations," Goldstein said. "Population growth in many regions has boosted water demand from a variety of economic sectors. Droughts and heat waves have diminished available water resources. In water-constrained regions, siting new power plants can be difficult due to public concerns about water availability and denial of water withdrawal permits."

Goldstein points out that the electricity sector is under more pressure from investors and lenders to prove that its water use will not have adverse economic impacts—and to demonstrate that it is effectively addressing water-related risks.

"Utilities need to understand the impact of their water use on regional resources and design water-saving plans that consider the demands of other users in an area," he said. "This is not an easy task, because there are many combinations of strategies that can be employed across a multitude of stakeholders, including electric power plants, industrial facilities, farms, and municipal users."

While not providing full analyses of the watersheds, the prototype applications in Ohio and Kentucky successfully tested the tool's design and function and demonstrated its versatility. Scenarios illustrated potential water impacts of retiring coal-fired power plant units, converting once-through cooling to closed-cycle cooling, decreasing per capita water use from the municipal and industrial sectors, and improving irrigation efficiencies. The tool yielded results consistent with current understanding of the watersheds.

The results are presented in *Water Prism, Volume 2: Prototype Applications* (3002002120). The report describes the watersheds, water-supply quantification methods, and data sets and illustrates the testing of water management scenarios. *Water Prism, Volume 1: Tool Development* (1023771) summarizes the tool's conceptual design and describes the major steps of a Water Prism analysis.



The output graphic of an analysis is a graphical "prism" that compares water supply and demand. Each color wedge in the prism represents the potential reduction in water consumption from strategies in different sectors.

How Water Prism Works

The tool is intended for use at a range of technical levels. Analysis begins with information on an area's available water supply. Next, water-use data from various sectors establish a "business-as-usual" projection of the basin's water balance.

If the analysis reveals a future water supply insufficient to meet demand, Water Prism can quantify the deficit and lead planners to evaluate various water-saving approaches. An analysis that reveals minimal risk can be used by utilities to reassure other watershed stakeholders and investors as well as for water use disclosures.

In refining the tool, EPRI is testing Water Prism on a semi-arid Texas watershed and conducting full-scale analyses in the West and Southeast. Power companies and other stakeholders can fund their own tailored Water Prism studies through an EPRI supplemental project.

For more information, contact Bob Goldstein, rogoldst@epri.com, 650.855.2154.

Nationwide Volt Demonstration Illuminates Electric Charging Demand

Distribution grid impacts of plug-in electric vehicles (PEVs) will remain modest in the near-term, according to a recent EPRI study involving the largest scale PEV research collaboration between the utility and automotive industries to date. This key insight from the two-year General Motors Chevrolet Volt Demonstration project validates previous EPRI research findings and will help utilities plan for the growing numbers of these cars.

General Motors, EPRI, and 30 utilities in 23 U.S. states and 3 Canadian provinces participated in real-time monitoring of PEV driving, charging, and consumer preferences. The project was supported by a $30.5 million grant from the Transportation Electrification Initiative administered by the U.S. Department of Energy through the American Recovery and Reinvestment Act.

Two Years of Data

As the adoption of PEVs accelerates, utilities need to understand the magnitude and timing of resulting demand growth and potential effects on distribution system operations and reliability. For example, a local concentration of large numbers of PEVs plugging in during peak electricity demand could overload a distribution circuit.

The Volt project was designed to shed light on demand by evaluating PEV driving and charging behavior, driving ranges of PEVs, and factors that influence driving range. The 30 participating utilities integrated a total of 68 Chevy Volts (2011 model) into their vehicle fleets. GM's OnStar telematics service and an EPRI-designed real-time data logging system wirelessly collected data on driving trips and charging events using a mobile network. EPRI processed data—such as air temperature and odometer, time, and battery charge gauge readings—on a monthly basis between August 2011 and August 2013 to draw insights.

Crunching the Numbers

EPRI's statistical analysis revealed a variety of driving and charging behaviors among the 68 Volts and a corresponding spread of the observed driving range across the study fleet. EPRI investigated the factors that affect this variability to develop a model to predict vehicle range.

EPRI researchers used a linear regression model to test how potential factors affect range and confirmed several expectations. For most vehicles, range increased with rising air temperatures, up to a certain threshold. Other predictors of range included:

- **Driving efficiency**. Range increased as the efficiency of electric driving increased. Efficiency is affected by heating, ventilation, air-conditioning, tire pressure, and other factors.
- **Vehicle speed**. Range typically increased as speed increased, up to an optimal speed, and then decreased after that point.
- **Weekday versus weekend driving**. In some cases, weekday driving yielded higher ranges than weekend driving; in other cases, the reverse was true. This is the result of varying local characteristics of weekday and weekend driving. Although the former usually involves commuting and the latter involves errands and social activities, both could be either low-traffic or congestion situations depending on the region.

The data indicate that average charging demand, given the current U.S. penetration of PEVs, is an extremely small fraction of available energy supply for overnight charging—much less than 1% for most parts of the grid. Near-term distribution system impacts for most utilities should be minimal, with one caveat: impacts will vary based on the characteristics of local distribution feeders and PEV charging rates. EPRI is conducting separate studies on feeder impacts.

EPRI plans to continue measurements of customer-driven PEVs to extend these insights, with the goal of providing utilities with tools to forecast total load from PEV charging on an hourly and daily basis—a capability that would improve distribution asset planning.

Moving Toward Smart Charging

To prepare utilities for anticipated growth in PEV sales, EPRI is developing "smart charging" technologies to manage when and how PEVs are charged and to optimize grid infrastructure for PEV charging. EPRI is engaged in demonstration projects with auto manufacturers and utilities to better understand how to cost-effectively implement such technologies on a large scale.

For more information, contact Marcus Alexander, malexander@epri.com, 650.855.2489.

Comprehensive Air Quality Research Looks at Natural and Man-Made Emissions for an Entire Region

For six weeks during the summer of 2013, EPRI participated in the Southern Oxidant and Aerosol Study (SOAS) to collect data on atmospheric gases and particles as part of a national $20 million research effort to shed light on air quality impacts of natural and man-made emissions in the Southeast United States. The study is designed to provide a comprehensive picture of the region's air quality by examining natural emissions from sources such as vegetation as well as man-made emissions from various economic sectors, including the electric power industry.

SOAS is one of several air quality studies under an umbrella national effort known as the Southeast Atmosphere Study (SAS) funded by the U.S. Environmental Protection Agency, National Science Foundation, and the National Oceanic and Atmospheric Administration. EPRI, Southern Company, and Tennessee Valley Authority (TVA) are providing financial support and research facilities.

SOAS is working to understand how natural and man-made emissions interact and influence the concentrations and fate of ozone, particulate matter, mercury, and other compounds in the atmosphere—and ultimately how these interactions affect regional air quality and climate in the Southeast. Because much about these interactions is unknown, large gaps remain in the scientific understanding of the impacts of man-made emissions. The Southeast is an ideal location to study these interactions because of the proximity of vegetative emissions combined with a variety of man-made emissions sources.

Providing Expertise, Analysis, and Infrastructure

EPRI, Southern Company, and TVA are providing SOAS researchers with extensive historical expertise on air quality in the region. Scientists have access to two decades of air quality and meteorological data from the Southeastern Aerosol Research and Characterization (SEARCH) Network—a series of air quality monitoring stations throughout the Southeast established in 1992 by EPRI and Southern Company—as well as from TVA's Look Rock Monitoring Station in Tennessee. This provides critical context as researchers interpret data collected in the campaign. In fact, SEARCH data have served as the basis of more than 200 peer-reviewed scientific publications to date.

The SEARCH station in Centreville, Alabama, was the focal point for ground-based measurements for SOAS. The Look Rock station was one of five satellite SOAS sites.

Centreville monitoring station during the Southern Oxidant and Aerosol Study

As a primary investigator for SOAS, EPRI installed new monitoring equipment at these stations and is analyzing trends in the SOAS and historical monitoring data. From this analysis, EPRI will co-author several scientific manuscripts, including papers with Envair, TVA, Atmospheric Research and Analysis, Inc., and Southern Company Services.

A Boost for Air Quality Science

Following substantial reductions in the region's man-made emissions—including those from the electric power industry—and with advances in monitoring technologies, scientists see this as an opportune time for a comprehensive study. Measurements can be taken at a frequency of seconds to minutes, instead of hours to days as in past research. Thousands of chemicals can be measured and characterized, compared to a handful in the past.

"Insights from these campaigns will form the basis of substantial new air quality research over the next several years," said Stephanie Shaw, senior technical leader for EPRI's air quality research. "We anticipate using the information to test new monitoring equipment, enhance atmospheric models, and ultimately inform effective air quality policy."

Shaw anticipates that improved models will help advance air quality science in other regions. She added that the overlap of research goals between EPRI and the campaign can bolster EPRI's collaboration with other institutions.

For more information, contact Stephanie Shaw, sshaw@epri.com, 650.855.2353.

TECHNOLOGY AT WORK

Member applications of EPRI science and technology

Smart Monitoring Initiative Eliminates 50,000 Manual Readings at Duke

Duke Energy, in collaboration with EPRI and National Instruments, has deployed throughout its power plant fleet a “smart” system of software and sensors that eliminates thousands of manual equipment readings every month, increasing reliability and lowering maintenance costs. The Smart Monitoring and Diagnostics initiative allows Duke to remotely detect equipment problems faster than ever, using automated, real-time diagnostics. It is expected to significantly reduce expensive failures of turbines, generators, transformers, and other critical equipment.

Automating Labor-Intensive Activities

With traditional, labor-intensive systems, power plant technicians devote large portions of their time to collecting data related to equipment maintenance. This typically requires workers to make rounds through a facility, using manual inspection technologies to gather data on hundreds of pieces of equipment. For example, Duke workers traditionally collect 60,000 data points on machinery vibration per month across the fleet, leaving little time for data analysis.

Duke’s Monitoring and Diagnostics Center has historically used a limited number of equipment sensors in plants to monitor basic process variables such as temperature, pressure, flow, and vibration. The utility sought expanded, smarter monitoring capabilities—more sensors deployed on a wider spectrum of components feeding data into a unified system for automated, continuous tracking and analysis.

Since 2010, EPRI has collaborated with vendors and utilities to map the architecture of such a smart monitoring and diagnostics concept, taking advantage of advances in wireless networks, automated data integration software, and sensors. The idea is to integrate low-cost sensors with a central database and software to identify problems and predict component failure—all at a fraction of the cost of conventional monitoring approaches. A plant operator can view a single screen that provides a comprehensive snapshot of the current conditions of a particular component based on all of the sensor data. This visualization can equip plant personnel to more quickly pinpoint equipment degradation and implement solutions—driving safer, more reliable operation.

EPRI expects that such capabilities will be crucial as plants age or are supporting more demanding operating requirements. For example, cycling of power plants designed for baseload operation has led to more equipment degradation, placing greater demands on maintenance workers.

Duke Energy’s Central Monitoring and Diagnostics Center in Charlotte, North Carolina

From Concept to Integrated, Real-Time Data Collection and Analysis

Duke worked with EPRI and National Instruments to install more than 30,000 sensors on more than 10,000 pieces of equipment to monitor vibration, temperature, oil level, and other parameters—eliminating 50,000 monthly manual equipment readings. The hardware and software collect and analyze the sensor data for the fleet 24/7.

Duke projects that its Center will provide real-time, integrated equipment health assessments and facilitate information sharing among engineers, managers, and monitoring specialists across the fleet. With its open software/hardware platform, Duke will readily be able to plug new sensors into the system.

Because smart monitoring and diagnostics is relatively new, technical challenges remain—including interoperability of systems and devices, instrumentation, data collection and management, diagnostic modeling, and security requirements. EPRI will develop and validate solutions to these challenges in a demonstration laboratory in Charlotte, North Carolina, and compile experiences and lessons learned in resource guides for industry stakeholders. Long term, EPRI is planning demonstration laboratories across the United States with remote monitoring capabilities, along with pilot-scale field demonstrations with other utilities and vendors, similar to the Duke project.

For more information, contact Brian Hollingshaus, bhollingshaus@epri.com, 704.595.2579.

EPRI Cyber Security Guidance Saves Texas Nuclear Plant $600,000

Luminant's Comanche Peak Nuclear Power Plant saved more than $600,000 on a digital system upgrade by using two EPRI guidance manuals on cyber security controls. The guidance helped Luminant understand and apply cyber security regulatory requirements in purchase specifications and contracts for a computer replacement and security video system at the Texas facility. This upfront work allowed Luminant to avoid expensive retrofits that otherwise would have been needed later to meet the requirements.

Step-by-Step Guidelines on Cyber Security Requirements

Nuclear power plants face increasing regulatory requirements from the U.S. Nuclear Regulatory Commission and the Federal Energy Regulatory Commission for cyber security of digital computer systems, communications systems, and networks. Intended to protect plants from cyber attacks that threaten safety and reliability, these requirements apply through planning, design, deployment, and maintenance. Plant owners considering digital system upgrades or modifications must account for more than 600 requirements—or risk costly redesign and rework.

Before 2010, guidance did not exist to help nuclear plant design engineers interpret and address these requirements through the various phases of a digital system modification. Because of the lack of clarity, some power plant owners had even postponed computer system upgrades.

To address these challenges, EPRI worked with Luminant and other nuclear utilities to create two guidance documents. Published in 2010, *Technical Guideline for Cyber Security Requirements and Life Cycle Implementation Guidelines for Nuclear Plant Digital Systems* (1019187) provides step-by-step procedures and checklists covering 138 areas of cyber security in detail—from passwords and wireless connections to encryption and intrusion detection. The report clarifies the requirements and provides examples of real-world application of the procedures. As a companion to the guidance, EPRI created a computer-based module that several nuclear plants have used to support cyber security training.

In 2012 and 2013, EPRI published and updated *Cyber Security Procurement Methodology* (3002001824), which provides guidance on procuring digital instrumentation and control systems with the necessary cyber security controls. The report is intended to put nuclear plant operators and suppliers on the same page regarding proper application of cyber security requirements. It guides operators through activities before and during communications with suppliers and explains how to evaluate supplier information.

Comanche Peak Nuclear Power Plant
Source: U.S. Nuclear Regulatory Commission

In 2014, EPRI plans to complete a computer-based training module on the procurement methodology for plant and vendor engineers.

Because cyber security requirements will largely remain the same, these two reports establish a standard approach to cyber security that will last over time.

Luminant Saves Money by Solving Problems Early

By 2013, Luminant's digital system upgrade project incorporated procedures of both manuals, enabling the company to detect and solve problems early during the contracts phase with its supplier and avoid $600,000 in unnecessary expenses during the design phase. This was facilitated by extensive discussions between Luminant and its supplier that led to a shared understanding of plant operators' computer cyber security requirements.

Jay Amin, digital program/cyber security program manager at Comanche Peak, attributed a large share of the project's success to the EPRI guidelines and methodology. "These reports are among the most valuable products that exist for addressing cyber security during all phases of a design modification."

For more information, contact Matt Gibson, mgibson@epri.com, 704.595.2951.

REPORTS AND SOFTWARE

Key deliverables now available

The following is a small selection of items recently published by EPRI. To view complete lists of your company-funded research reports, updates, software, training announcements, and other program deliverables, log in at www.epri.com and go to Program Cockpits.

Calvert Cliffs Stainless Steel Dry Storage Canister Inspection (1025209)

Inspecting stainless steel containers used for long-term dry storage of spent nuclear fuel can shed light on stress corrosion cracking—a form of degradation from exposure to corrosive atmospheric conditions, including those near salt water. This report describes results of the first such inspection at Calvert Cliffs Nuclear Power Plant, which successfully demonstrated the ability to remotely access the canister surface, obtain visual evidence of the surface condition, take temperature measurements, and collect surface samples.

Assessing Compressed Natural Gas and Electricity as Transportation Fuels for Utility Fleets and Utility Customers (3002000295)

As the use of natural gas and electricity for transportation fuels grows, combined electric-gas utilities must decide how to advise customers and fleet managers who are considering a transition from gasoline or diesel to electricity or natural gas. This report describes supply and pricing trends in the electric and natural gas transportation industries, analyzes policies and markets for plug-in and natural-gas-fueled vehicles, and provides utilities with guidance on how to assist their customers.

Nuclear Maintenance Applications Center: Nuclear Fuel Handling Equipment Application and Maintenance Guide (3002000642)

Fuel handling is a critical task during a nuclear power plant refueling outage. This report is intended to familiarize nuclear power plant maintenance and engineering personnel with the design and function of fuel-handling equipment. The report draws from industry experience with equipment operations to provide guidance on preventive maintenance, repair, and replacement.

2013 Grid Strategy: Operating the Grid with High Penetration of Distributed Energy Resources (3002000813)

Operating the distribution grid with more extensive deployment of distributed energy resources (DER) is a key focus for the electric utility industry. This report summarizes challenges in this area, describes distribution feeder planning analyses to help interconnect DER safely and reliably, and assesses how utilities are currently operating feeders with significant DER penetration. Modeling results from a test feeder provide insights on techniques to reduce the impacts on voltage regulation devices.

Coal Combustion Residuals Pond Closure: Guidance for Dewatering and Capping (3002001117)

The U.S. Environmental Protection Agency's final rules for disposal of coal combustion residuals (CCRs) are expected to lead to the closing of a significant number of CCR ponds. This report provides power companies with comprehensive engineering guidance on dewatering and capping CCR ponds. It also includes information on geotechnical and hydrogeologic investigations, hydrologic design, construction and operation, and post-closing care.

Performance Evaluation of a Thermosyphon Cooler Hybrid System at the Water Research Center at Plant Bowen (3002001594)

This report describes the performance of the Thermosyphon dry cooling system, developed by Johnson Controls, Inc. and installed as a pilot demonstration at the Water Research Center at Georgia Power's Plant Bowen during a year-long test. The data revealed monthly water savings of 34–78%.

Electric Generation Expansion Analysis System (EGEAS) v10.0 (3002001929)

The Electric Generation Expansion Analysis System software can be used by utility planners to produce integrated resource plans, evaluate independent power producers, develop avoided costs and environmental compliance plans, and analyze life extension alternatives. It can help determine a least-cost generation expansion plan or simulate detailed costs for plan options.

Layup for Cycling Units: Requirements, Issues, and Concerns—An EPRI White Paper (3002003972)

Proper layup practices at idle power plants are necessary for optimal performance, yet such practices are typically not used in plants that cycle. This white paper describes the component damage that results from inadequate layup practices during unit shutdown as well as practical techniques to protect equipment.

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