SUMMER 2013

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ELECTRIC POWER RESEARCH INSTITUTE

What comes next for:
Power Generation & Grid Management

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A Material for the Ages? NDE Can Provide Concrete Answers

U.S. Shale Gas Production: An Analytical Review

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Art: Cover and pages 6, 10, 14, and 20 by Craig Diskowski/Edge Design.

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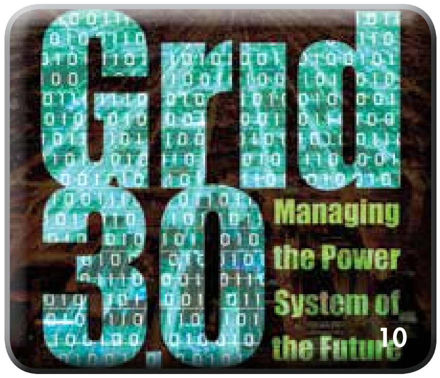

VIEWPOINT

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VIEWPOINT

by Mike Howard, President and CEO, EPRI

From Technology to Tinseltown: The Focus of R&D in a Time of Fundamental Change

What do Hollywood and the electricity sector have in common? Both face essential changes to their business model due to fundamental changes in the way their products are produced, delivered, and used. The rise of cable networks and Internet companies in the entertainment business is rewiring both the production and the delivery of entertainment. Customers now choose from offerings that range from the cinema to the smart phone. Today, low-budget or no-budget YouTube videos compete with major motion pictures for consumers' time and attention.

At EPRI, we believe the electricity sector is on the verge of a similar change. Society will continue to depend on utilities' size and strength for capital investment, technological leadership, operational expertise, and essential infrastructure. But elements of the system that produces and delivers electricity will become more diverse, as will the products and services.

In this issue of *EPRI Journal*, we highlight a report that looks at issues and trends that are driving changes in the generation portfolio. The industry is moving from almost complete reliance on a handful of baseload technologies to a diverse portfolio of baseload, load-following, and variable renewable power generation. We must also develop and integrate a portfolio of balancing resources that includes energy storage, demand response, smart inverters, and other technologies. Because these assets require so much capital, it is important for power producers to vet the technologies and assess the business landscape thoroughly.

E.ON Senior Vice President for technology and innovation Urban Keussen describes the rapid evolution of Germany's power system and its business model as the country transforms its generation fleet. We see how renewables will continue to come into their own, and we see how they might drive us to a more distributed or decentralized grid. And just like moviegoers with smart phones, E.ON's customers are viewing the product and their options in entirely new ways.

Also in this issue, we're reporting on research that will help prepare the utilities for what we call "Grid 3.0." The changes that Urban Keussen discusses point to how utilities will require more computing power and better software to deal with massive amounts of data, to forecast demand, and to meet that demand using traditional and intermittent renewable energy. Our research is looking at how and where the industry must focus its information technology to create the new grid.

There's no question that digital technology will both require and result in enormous amounts of data and information. And we should not assume that millions of people who routinely consume entertainment on their smart phones will somehow exempt their power suppliers from their changing expectations. Sooner or later they will expect to hold their options in the palm of their hand. Those options might include time-of-day pricing or the opportunity to sell power from their own solar panels back to the grid.

This issue of *EPRI Journal* points us to other important areas of research as well. It's not all about technology or Tinseltown. It's about concrete issues such as . . . concrete. From hydroelectric dams to reactor buildings to foundations for substations and wind turbines, this familiar material is benefiting from new methods to assess its condition and ensure its integrity. Just as the entertainment business will continue to rely on products that cost hundreds of millions of dollars, so too will power production and delivery require money at such a scale for each major component of its infrastructure—and it will be ever more important to make that infrastructure as long-lasting, reliable, and cost-effective as we can make it.

Michael W. Howard
President and Chief Executive Officer

SHAPING THE FUTURE

Innovative approaches to upcoming challenges

Ion Transport Membrane Technology for Advanced Coal Plants

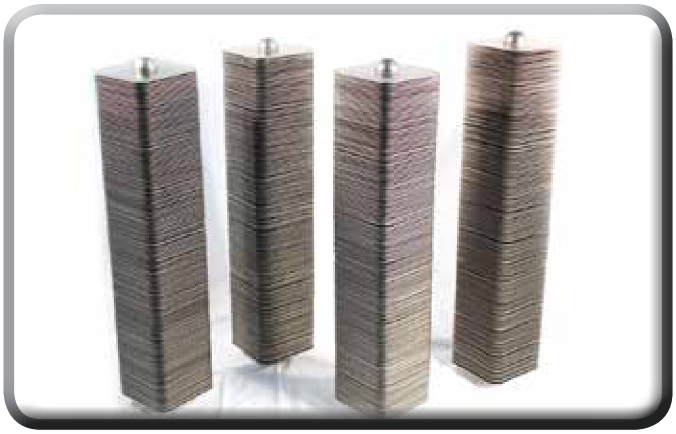
Coal continues to play a significant role in the production of energy worldwide. However, if carbon constraints are imposed, coal power will need advanced technologies to continue to be competitive. Two such processes that could lower cost if carbon capture and storage (CCS) becomes necessary are integrated gasification–combined-cycle (IGCC) operation and oxy-combustion. Both can require large quantities of oxygen, though, which today is provided by cryogenic air separation. While this technology is mature, it is power intensive and therefore relatively expensive.

Recognizing the pivotal influence oxygen economics is likely to have on advanced coal generation with CCS, EPRI's CoalFleet for Tomorrow® program is investigating alternatives to the cryogenic approach that could reduce the cost and power consumption of air separation. After a review of potential technologies, EPRI chose a novel air separation technology—the Ion Transport Membrane (ITM) Oxygen process from Air Products and Chemicals, Inc. (APCI)—and formed a collaborative to help demonstrate the feasibility and value of its integration with emerging advanced coal power plants.

Development and Demonstration

The ITM Oxygen process is based on ceramic membranes that selectively transport oxygen ions when operated at high temperatures. Under the influence of an oxygen partial-pressure driving force, the electrochemical ITM Oxygen process achieves a high-purity, high-flux separation of oxygen from air. Because the membrane materials conduct electrons as well as ions, no external source of electric power is required to operate the process. The air separation system produces a hot, pure oxygen stream and a hot, pressurized, oxygen-depleted stream from which significant amounts of energy can be extracted. This process lends itself well to integration with advanced power generation systems to produce electricity and steam in addition to oxygen.

An APCI-led team began development of ITM Oxygen in 1988 in partnership with the U.S. Department of Energy (DOE). Phase 1 of the DOE-funded program focused on the technical feasibility of the ITM Oxygen approach. In Phase 2, commercial-scale modules were developed and built; APCI has successfully demonstrated these modules, which produce 1 ton per day of oxygen, in a prototype facility that produces up to 5 t/d. The ongoing Phase 3 involves the design, construction, operation, and testing of a 100-t/d intermediate-scale test unit (ISTU) that integrates ITM Oxygen with turbomachinery.



Air Products and Chemicals' 1-t/d ITM Oxygen modules

In a parallel effort, APCI is participating in Phase 5 of the DOE program, focused on scale-up for a larger plant that could produce 2,000 t/d of oxygen. APCI is also investigating the application of ITM Oxygen for natural gas–powered systems, as well as for systems in other industries—particularly industries, such as steel production, that use high-temperature processes.

EPRI Collaborative

EPRI teamed with APCI in 2009 to form a power industry–led collaborative to support the development of ITM Oxygen during the current Phase 3 of the DOE program. The EPRI collaborative consists of six utility participants, which have contributed $6 million in funding for the multiyear demonstration project.

EPRI's role was to model the ITM Oxygen process as applied to IGCC and oxy-combustion power plants, to assess its economics and performance, and to provide integration schemes for ITM Oxygen in such applications. This project also provided APCI with the perspective of the power industry—including the industry's needs and potential technical issues that might arise related to applying ITM Oxygen for power plant use.

The end goal was to help bring the technology to a stage at which it could be used to benefit the power industry and the public. Results of the EPRI study have shown that ITM Oxygen has the potential to significantly reduce the cost of oxygen compared with conventional cryogenic oxygen plants in advanced coal power generation applications.

Involvement in the ISTU demonstration was a cornerstone of the EPRI collaborative project. Construction of the facility is now nearly complete, with startup planned for March 2014, followed by several years of testing.

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Scenario Planning to Stress-Test R&D Focus

One of the most formidable challenges facing the electricity sector and its stakeholders is envisioning how future uncertainties will affect companies' technology strategies and related business plans.

One way to meet this challenge is to create a set of scenarios that project the potential outcomes of uncertain factors—without any attempt at prediction—and develop effective responses. Looking out to 2030, EPRI developed such scenarios to "stress-test" its R&D portfolio—to assess its robustness, help focus research emphasis, and identify gaps that should be filled to ensure a no-regrets strategy for the overall program.

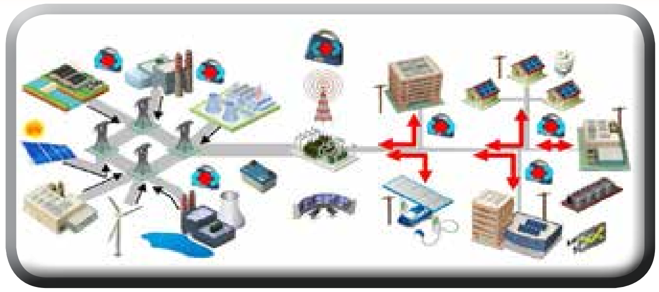
Possible Outcomes, from Alpha to Omega

Scenario planning has some clear advantages over conventional, business-cycle planning methods—specifically, the ability to

- remove biases in visioning;
- challenge the view that little will change;
- frame a probabilistic versus a deterministic view of the future;
- organize perceptions about future alternatives;
- focus debates about technology needs; and
- guide development of alternative technology portfolios.

Working with its Research Advisory Committee and other utility advisors and stakeholders, EPRI identified three drivers expected to have critical effects on the industry's future: electricity demand, the price of natural gas, and environmental and regulatory policies. EPRI's scenario planning efforts differ from those that other electricity industry stakeholders may use in that they hold technology as an independent variable. The intent is to understand what technologies may be needed for the industry to deliver safe, reliable, affordable electricity. Utilities' scenario plans would include technology as a key driver itself. The final report on scenario planning (3002001496) includes extensive discussion of EPRI's drivers, including how they might interact and how they relate to external factors, including global economics, extreme weather events, public opinion, and digital technology development.

Two scenarios were developed to define the boundaries of change for the industry, serving as "bookends" for likely outcomes. Scenario Alpha (considered the most likely scenario for the United States) assumes moderate to high natural gas prices ($4 to $7 per million Btu over the next 20 years) and expansion of environmental and energy policies, including new clean energy initiatives and enactment of carbon legislation; Scenario Omega assumes continued low natural gas prices and status quo environmental and energy policies. Note that status quo here includes existing policies that already have built-in "ratchets" that are



Tomorrow's power system will still rely substantially on large central station generation but will increasingly make use of microgrids, distributed renewable generation, and electric energy storage.

intended to evolve over prescribed periods. Because of uncertainty in the evolution of customer self-generation, there was less consensus on the issue of future net load growth, with about half the executives surveyed expecting flat or declining growth and the other half expecting what is today considered modest growth, approaching 1% to 2% a year. Therefore, EPRI considered a range of consumer demand for electricity supplied by grid services in both scenarios.

Stress Test Results

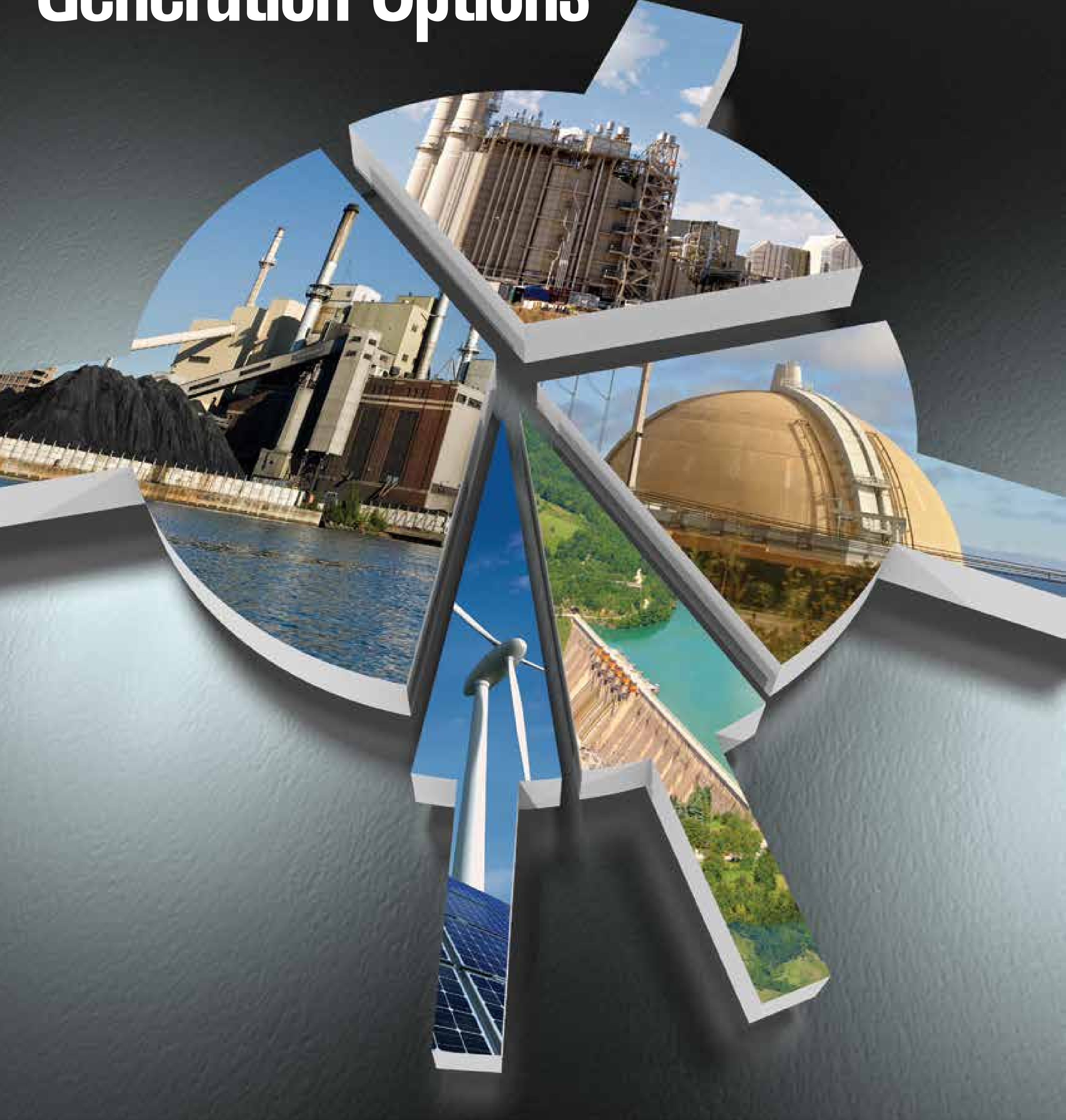
Looking to 2030, the scenario planning pointed up the industry's general need for increased flexibility, resiliency, and connectivity. The final report assesses the importance of the six strategic issues in EPRI's R&D portfolio—energy efficiency, long-term operations, near-zero emissions, renewable resources and integration, the smart grid, and water resources—with regard to both scenarios. Specific R&D program areas are rated for robustness, and moderate and critical gaps are identified for consideration of additional research emphasis.

Review of the scenarios' technology implications relative to the existing EPRI program revealed the need to

- consider the electricity sector's role in assessing the natural gas supply system's security, efficiency, and flexibility;
- reinforce R&D regarding long-term operations of coal and nuclear power plants;
- continue R&D related to carbon capture and sequestration and options for using recovered carbon dioxide;
- understand the operation and integration of microgrids with existing bulk power systems; and
- consider product development in technologies that would enable the industry to deliver new products and services, including those powered by both grid and non-grid energy resources.

For more information, contact Clark Gellings, cgellings@epri.com, 650.855.2610.

Balancing an Expanding Array of Generation Options



THE STORY IN BRIEF

Changes in fuel choice, economics, regulation, and load growth will strongly affect the power generation landscape over the next decade. A new EPRI analysis of the emerging trends suggests a broad, diverse generation portfolio that will integrate the best new technology to serve a carbon-constrained future.

The history of electric power is marked by transitions where new generation technologies have tapped previously unconsidered energy resources. Each new technology has not so much displaced earlier forms as augmented and diversified the range of possibilities. Power provided by old stalwarts hydro and coal was supplemented in the 1970s and 1980s by nuclear power, followed by gas-fired combustion turbines in the 1990s and 2000s, followed by today's small but gathering wave of solar power and onshore wind. On the energy horizon are offshore wind, enhanced geothermal, and small modular nuclear reactors. An expanding portfolio has strengthened the electric power industry, fostering competition, driving down costs, and providing balance and resilience for utilities making long-term investments during uncertain times.

Major Uncertainties

Uncertainty seems to be the watchword among generation planners. "One of the themes that I continue to hear is just how uncertain things are in the industry," said Robin Bedilion, project manager at EPRI and primary author of a key 2012 report on generation technology options. "There is uncertainty about CO_2 emissions regulations, natural gas prices, and integrating large-scale renewable options into the grid. Uncertainty surrounds water, technology development, the feasibility of carbon capture and storage, capital costs, capacity factors, even load growth. With the reduction in electricity demand during the recession and continued improvements in energy efficiency, future load growth may not be what it once was."

U.S. coal-fired generation faces proposed regulation under federal New Source Performance Standards that would impose limits on CO_2 emissions equal to those of natural gas combined-cycle (NGCC) technology, amounting to a 50% reduction. This would require all new coal plants to employ carbon capture and storage (CCS) technology in order to operate—a daunting prospect, given the capital expense and the limited state of technology deployment. The overriding expectation is that there will continue to be pressure to reduce CO_2 emissions. Congressional initiatives, along the lines of the Waxman-Markey Bill, are stalled. However, the U.S. Environmental Protection Agency (EPA) continues to pursue regulatory actions under the Clean Air Act, effectively putting new coal-fired generation on hold.

Natural gas is the logical beneficiary of this impasse. Fuel prices dropped significantly following the boom in shale gas, and NGCC technology seems unbeatable in nearly every competitive aspect—lower capital costs, fast installation, flexibility in scale and operation, high efficiency, lower emissions, and fast-start capability to firm up variable generation. However, having been once burned by high expectations, utilities are cautious. "There is still hesitancy on the part of generation planners," said Bedilion. "They remember the historic volatility of gas prices and are not eager to put all their eggs in the natural gas basket." In the late 1990s and early 2000s, gas prices were low, and a construction boom between 2000 and 2005 saw a significant increase in installed natural gas plant capacity. By mid-decade, gas spiked, and many of these plants became too expensive to run. "At that point, coal looked good," pointed out Bedilion. Could it happen again, given the magnitude of shale gas resources? "The long-term price outlook from the U.S. Energy Information Administration [EIA] is much lower than it was just a few years ago. But we could start exporting our gas in the form of LNG [liquefied natural gas], and there is continued debate about what that would do to the natural gas price here at home. Generation planners continue to try to quantify the value of fuel diversity in the generating fleet."

Renewables face their own uncertainties. They remain dependent on energy policy and incentives for their development, deployment, and comparative economics. Renewable portfolio standards (RPS) have a long-term horizon that planners can count on, but other factors, such as the production tax credit (PTC), remain captive to policy swings. "At the end of 2012, with uncertainty around whether the PTC was going to be extended, there was a huge build-out of new wind before the end of the year," said Bedilion. Given the rush to build, total wind capacity in the United States jumped from just over 45 gigawatts to approximately 60 GW in one year.

In 2012, the U.S. Nuclear Regulatory Commission approved two applications to build and operate four new nuclear reactors, the first reactors to receive construction approval in over 30 years. Nuclear has distinct advantages but continues to face the challenges imposed by high capital costs and long lead times. Moreover, public concern following the Fukushima Daiichi event may discourage nuclear power development in the United States and Europe.

Portfolio Trends

Today's generation portfolio has been summarized in the EPRI report *Integrated Generation Technology Options* (1026656), which provides technology updates and comparative economics for ten major options in 2015 and 2025. It also shows how they might fare economically in a carbon-constrained world.

Although regional variation is large, the nation's portfolio is slowly shifting away from coal toward gas and renewables. Coal-based capacity additions have effectively stopped, and retirement of existing coal units has accelerated. The fleet is aging; nearly 75% of coal-fired capacity is now more than 30 years old. Fuel trends are also eating away at coal's traditional competitive advantage. Coal is now an international commodity, facing upward price pressure as China becomes a large importer. Utility planners anticipate escalating fuel cost, coupled with increasing capital costs. As a consequence, coal's share of U.S. electricity generation declined from 49% in 2007 to 37% in 2012, while gas-fired generation climbed to 30%. Nuclear and large-scale hydro held their own at 19% and 7%, respectively. Non-hydro renewables, despite dramatic growth, are now about 5% in aggregate, with wind accounting for most of the capacity expansion.

The portfolio is anything but static. "EIA data show that we are right around the point where the fuel switch between gas and coal happens," said Bedilion. "If gas prices go up, more coal is dispatched, and vice versa. In April 2012, gas and coal were equal in their net power generation contributions for the first time—about 33% of total generation each—and then they split apart as gas prices edged up."

Renewables' contribution to the portfolio is to a large extent dictated by law. Thirty states now have mandatory renewable portfolio standards. Hawaii's standard is the most aggressive, calling for 40% renewable electricity generation by 2020. California's is next at 33%, and Colorado's stands at 30% by 2020. With federal and state incentives, capacity growth in both wind and solar remains strong. The United States now ranks second only to China in global deployment of wind power.

For more than 30 years, the price of solar photovoltaics (PV) has dropped about 20% for every doubling of installed capacity. In recent years, the drop in price has been even more precipitous. Total capital requirements for PV dropped from about $8,000/kilowatt in 2009 to around $2,500 in 2012. Levelized cost of electricity (LCOE) for the technology showed similar decline.

Emerging Technology Trends

EPRI analysis assumes that in the 2020–2025 time frame, plants that today burn pulverized coal (PC) directly will incorporate CO_2 capture and storage (CCS). Postcombustion technology is one route for CO_2 capture, and here the most mature candidate is the amine separation process used in the petrochemical industry. Integrated gasification–combined-cycle (IGCC) technology would rely on precombustion capture. Three IGCC plants with CO_2 capture are under construction or in advanced development in the United States; two are designed for 90% CO_2 capture. High capital costs continue to confront both IGCC and CCS, but accelerated RD&D might bring these costs down.

Offshore wind energy development is under way in Europe and nearing the jumping-off point for large-scale development in the United States and China. By 2012, roughly 4 GW of offshore wind capacity was operational in Northern Europe, mostly in the English Channel and North Sea. Currently, the UK's Walney Wind Farm, at 367 megawatts (MW), is the largest offshore facility in the world. It will be dwarfed by subsequent wind farms now being developed, such as the Dogger Bank farm, which could grow into a multigigawatt-scale plant. DOE says that U.S. offshore wind has the potential to produce 54 GW by 2030, roughly comparable to today's onshore wind capacity, with the advantage of operating close to major load centers.

Most commercial PV installations are based on well-understood crystalline silicon technology. That technology's long-term competitor is the less mature thin-film PV, which lends itself to process production in continuous sheets. Crystalline cells' efficiency ranges from 14% to 21%, compared with 7% to 12.5% for thin film. Over the long term, however, advances in thin-film efficiency are expected to outpace advances in crystalline, narrowing the performance gap. Multijunction PV, in which different bandgaps are layered, has shown laboratory efficiencies above 40%, providing a glimpse of the technology's potential.

A central drawback for PV systems and wind plants is that they can drop off the grid quickly as sunlight or breezes decline, forcing operators to keep resources on hand to firm up supply and maintain voltage support. Integrating such variable generation is a primary challenge facing transmission planners, regional transmission operators, and reliability coordinators. Remote resources may require new transmission lines, a smarter grid, and greater interregional cooperation in reliability-based operations.

The nuclear industry is developing small modular reactors (SMRs) that may be able to sidestep conventional plants' high capital cost and long lead times. SMR units will likely be smaller than 300 MW. Several designs are derived from large-scale nuclear reactors; however, they have fully integrated the steam generation function inside the reactor vessel itself.

Enhanced geothermal systems (EGS) could open the geothermal potential of vast regions of the United States. The technique involves fracturing dry hot-rock formations as deep as 10 km (6.2 miles) by using horizontal drilling technology, then circulating surface water through the fractured rock to extract heat for power generation. While the technology is still in the R&D phase, a 2007 Massachusetts Institute of Technology study estimated the potential of U.S. EGS to be 100 GW of cost-competitive geothermal electricity by 2050.

Comparative Economics

Comparing generation options is never easy. It requires a common, realistic framework and dozens of critical assumptions. EPRI's generation technology options report presents a high-level comparison of ten major options for 2015 and 2025 using LCOE. Technologies with varying capital costs, fuel costs, fixed and variable operation and maintenance costs, and capacity factors can be compared on a common basis using consistent assumptions. However, while LCOE is used throughout the utility industry as a high-level screening tool, actual plant investment decisions are affected by other, project-specific considerations. "One of the new aspects of the most recent report is the separation of the dispatchable and nondispatchable technologies in LCOE comparison charts," said Bedilion. "With the rapid decrease in cost for wind and photovoltaics, they show up on the same scale for the cost-of-electricity comparison chart for the first time. Without qualification, this information might lead people to wonder why utilities are not installing more wind and PV. By itself, the chart does not capture the value of dispatchability or, conversely, the cost of integrating variable sources into the grid." Integration costs can include the need for additional operating reserves, backup generation, storage, and new planning tools.

For the 2015 portfolio, the LCOE for dispatchable technologies ranged from \$30/megawatt-hour for NGCC at low gas prices to around \$123/MWh for biomass. NGCC at higher gas prices was clustered with PC at \$77/MWh, IGCC at \$88/MWh, and nuclear at \$90/MWh. In the non-dispatchable area, which excludes the costs of grid integration, the median LCOE for wind was \$90/MWh, while for PV it was much higher, \$155/MWh.

For 2025, with the exception of nuclear, the LCOE costs for dispatchable technologies are higher because of the inclusion of CCS for PC, IGCC, and NGCC. CCS added about \$30–\$40/MWh to NGCC, bringing the LCOE for gas-fired generation up to \$70–\$110. IGCC and PC, both with CCS, climb to \$110–\$128/MWh. Nuclear, maintaining its current cost structure of \$90/MWh, becomes quite competitive with all other baseload generation.

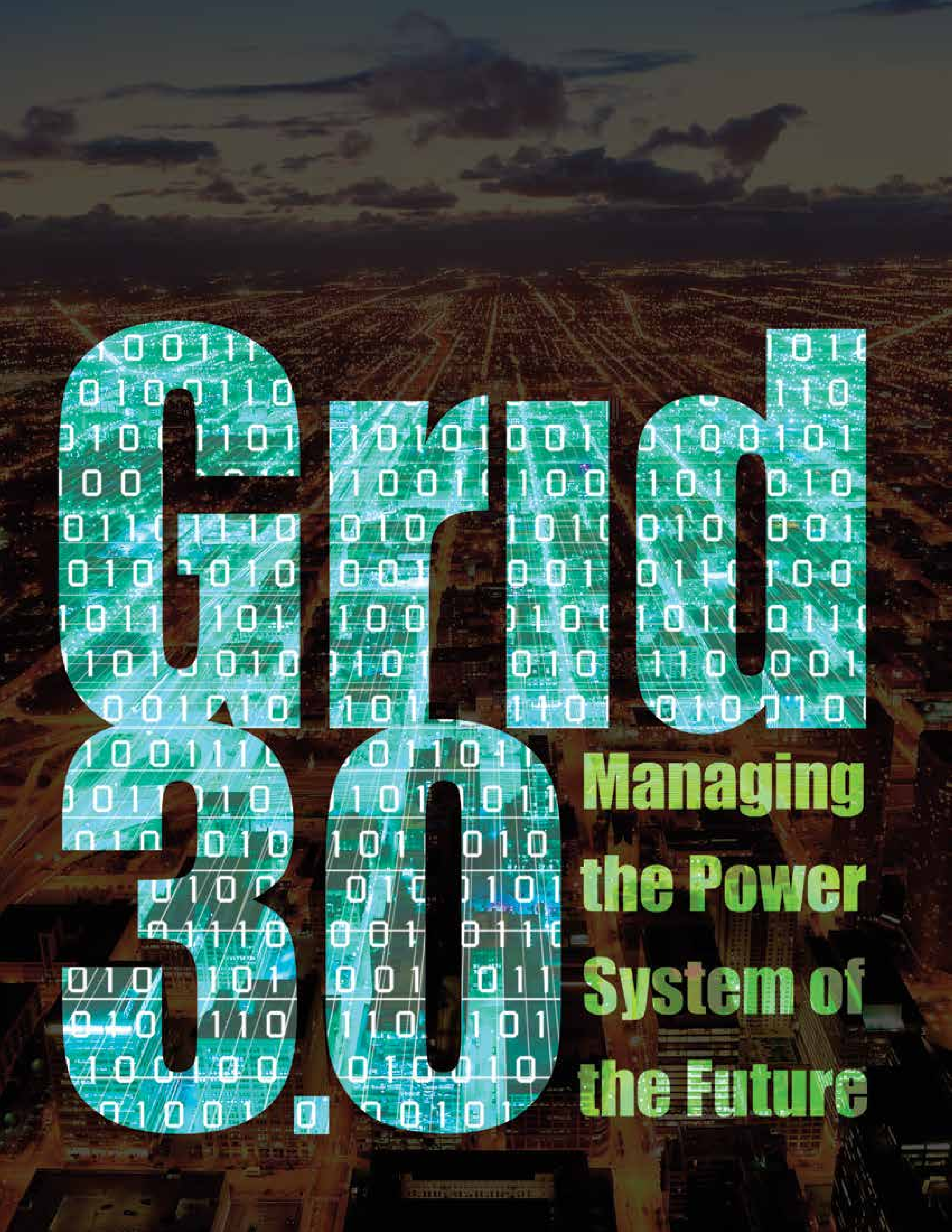
In contrast to the generally rising costs of dispatchable generation, the LCOE for nondispatchable technologies declines substantially over the next 10 years, assuming continued R&D and capacity expansion. The median value for wind drops from \$90/MWh in 2015 to \$75/MWh in 2025, while the median value for PV drops from \$155/MWh to \$115/MWh, with the bottom of EPRI's PV range for 2025 at about \$80/MWh.

"There are numerous assumptions built into the analysis that could be a source of debate," said Bedilion. "One we've gotten feedback on is the 80% capacity factor assumed for gas-fired generation; historically these plants operate at a much lower level." To make the analysis more useful to generation planners, Bedilion described the next step in EPRI's program. "We are trying to develop an interactive generation options web tool in which users could change assumptions about fuel prices, capacity factors, and the like, and run what-if scenarios."

For the foreseeable future, the portfolio of low-cost generation options will continue its historic drive toward diversity. While the analysis in an age of uncertainty will become increasingly complex, the range of possible solutions will grow to help meet the challenge.

This article was written by Brent Barker. Background information was provided by Robin Bedilion, rbedilion@epri.com, 650.855.2225

Robin Bedilion is a project manager in EPRI's Strategic Energy Analysis group with a research focus on interdisciplinary analysis of technology development, energy policy, and economic factors. Bedilion joined EPRI in 2007 under the Technical Assessment Guide program and holds a B.S. degree in mechanical engineering from Santa Clara University and an M.S. from Stanford University in the same field, with specialization in energy systems.



Grid 3.0

Managing the Power System of the Future

THE STORY IN BRIEF

The electric power industry will need supercomputers, advanced sensors, new visualization tools, and other innovative technologies to manage the operation of tomorrow's increasingly diverse and interconnected grid.

The electricity grid, as the backbone of our energy network, is undergoing a transformation—a metamorphosis driven by renewable energy, smart technologies, distributed resources, and the underlying capacity to manage more data from more sources than ever before. Utilities increasingly agree on what the new grid will look like, but they are less certain about the best strategies for getting there.

EPRI launched a project in 2011 to develop an overview of this significant shift and to evaluate potential technical solutions that will enable utilities to continue to deliver electricity reliably and affordably. The project's goal is to prepare the utilities for the next-generation grid, sometimes referred to as Grid 3.0, which will require more computing power and better software to process and analyze massive amounts of data, to forecast demand, and to meet that demand with supply from a combination of centralized, baseload power generation and distributed, intermittent power generation.

With Georgia Institute of Technology as a research partner, EPRI is focusing on developing software applications for running this new and more complex energy management system. The goal is to create a more seamless process for planning, operations, and postoperational analysis of the systems—a process based on high-performance, parallel computing power, which will deliver faster and more accurate results.

The beefed-up computing power will enable utilities to carry out contingency analyses that incorporate multiple scenarios at the same time while also reducing redundant efforts. To make more effective use of the data and to improve planning and execution, utilities will benefit from 3-D visualization tools for forecasting energy demand and the capability of the power plants and grid to meet it.

"We are putting together core pieces to demonstrate the balance that has to take place between load and generation on a real-time basis," said Paul Myrda, the EPRI technical executive in charge of the project. "Wind, for example, is extremely variable. How does one plan ahead to dispatch the appropriate units to compensate and react to it in real time?"

EPRI and Georgia Tech researchers have progressed from sketching ideas to developing proof-of-concept designs. They plan to bring those designs out of the lab in 2015 and make them available to software companies, which can then develop them into commercial products.

From Grid 1.0 to 3.0

The grid has come a long way since its birth in the 1800s. Supervisory control and data acquisition (SCADA) systems emerged in the 1950s to manage the growing number of power plants and power lines that were spilling from cities into rural regions. Back then, utilities manually controlled the ramp-up and output of their power plants. Today, with Grid 2.0, much more powerful SCADA systems have been integrated into comprehensive energy management systems to manage the expansion and interconnection of regional grids that emerged in the 1960s. The computers became powerful and sophisticated enough to manage multiple interconnections between centralized power plants and to ensure a balanced supply and demand among the many utilities in the market. The technology has also given utilities and grid operators indications of power plant and grid performance about 20 to 30 seconds after the fact.

Now comes the start of a new stage for the grid. The regulatory push and funding in recent years to modernize the grid by installing smarter meters, digital communication networks, and sensors are enabling more precise grid monitoring and generation of a growing amount of data on energy production and grid performance. The emergence of renewable energy generation, with intermittent sources such as solar and wind, makes it more difficult to predict and manage the electricity supply and balance of this more complicated system. Renewable energy sources increasingly include both large, centralized power plants and distributed units, such as rooftop solar panels. Policies to promote the sale of excess electricity from these small power generators in the distribution network drive the need for a more powerful and sophisticated energy management system. The gradual increase in sales of electric cars and the use of batteries or other types of energy storage by consumers and solar and wind plant owners will require additional planning to make them fit well into the grid's operation.

Grid 3.0 will require new computing hardware, sensors, and software to integrate all these new additions to the grid, ensure their interoperability, and manage new market mechanisms for buying and selling renewable electricity and power from energy storage systems.

The Attack Plan

Enhancing the system is a daunting task. For the Grid 3.0 project, EPRI is focused on four areas where new software development will enable its utility members to work with some of the key changes and, more important, to use a model designed to manage many more moving parts.

Current limitations. Research in the first area looks at the limitations of applications used for planning and operations and for conducting postoperational analyses, with the goal of creating a more seamless planning and management model for the power plants and grid. Currently, the process uses disparately developed software and protocols for each of the three segments, which makes it difficult to do comparative analyses and create a unified strategy from planning to execution. Given the complexity of Grid 3.0, it is more important than ever for utilities and grid operators to have a systematic approach that allows them to work more efficiently and save money and time.

High-performance computing. The second research focus is on ways the utility industry could adapt the high-performance computing commonly used by financial institutions, Internet companies, and automakers in carrying out the heavy data processing and analyses needed for engineering and financial transactions. High-performance computing makes use of supercomputers, which typically run on tens of thousands of traditional processors and incorporate graphics processors to speed up the more intensive parts of the calculations. These configurations excel at parallel computing—running multiple computational calculations at the same time—to divide a big problem into smaller pieces and to solve them concurrently. This approach is very different from the computing architecture commonly employed in the utility industry, which uses less powerful computers with traditional processors that can solve only one problem at a time.

"With the growing amount of data from sensors and smart meters and the need for better energy production and consumption forecasts to run the grid, utilities should take advantage of parallel computing to get the real-time analyses needed to operate more efficiently," said Leilei Xiong, a Georgia Tech researcher. Switching to a different computing architecture will require new software designed to meet utilities' needs. The researchers will first identify the scale and availability of the computing power necessary to deliver real-

time analyses and then consider which algorithms are best suited for processing utility data.

Contingency analyses. The project also aims to improve contingency analyses of the power grid. Contingency analyses currently simulate and quantify potential problems linearly, one at a time, to anticipate possible causes of system failures and blackouts and help utility staff identify effective repair solutions ahead of time. These analyses typically run repeatedly every few minutes with the same types of data input. Because the analyses are carried out for both planning and operations, they often create unnecessary redundancy. And though this method has worked well in the past, it won't be as efficient or provide sufficiently accurate predictions in the more dynamic grid of the future. Managing the two-way flow of electricity between centralized and distributed renewable generation will require software that can

- simulate multiple scenarios across different parts of a utility's territory;
- equip utilities to better coordinate planning and prevention; and
- support effective planning to fix equipment failures and deal with emergencies.

Visualization tools. The fourth part of the project sets out to develop better visualization software. Visualization tools are useful for understanding complex data and homing in on information that is critical for planning and for operating power plants and the grid. Current visualization programs usually present data in two dimensions and lack the ability to project potential scenarios in the hours or days ahead, which will be necessary for managing the integration of distributed resources and renewable energy into the grid.

The improved web-based visualization tools can create 3-D views of the data and provide navigational features that will enable utilities to examine real-time performance data more closely and create forecasts from different parts of their operations at different times. To develop the prototype, researchers will select sample data sets and experiment with algorithms for retrieving and processing utility data.

At the end, the researchers will combine these elements—new computing power, dynamic contingency analyses, and 3-D visualization and navigational tools—to create a prototype architecture for the next-generation energy management system.

What Lies Ahead

Today, the utility industry recognizes this wholesale transformation of the grid to be in its early stages. Many utilities are already carrying out pilot projects to target specific trouble spots, such as the impact of electric car charging, and are designing solar inverters for better voltage control. But the grid of tomorrow will require even more sweeping changes in its planning and operations, from power generation to delivery.

EPRI recognizes the difficulties in redesigning energy management systems to respond to future needs. The Grid 3.0 project takes this huge challenge and divides it into four manageable parts that will eventually be integrated to create a new model. To reach this goal, utilities and software developers alike will have to be willing to join in the effort to stay ahead of major developments rather than merely react to them.

> The project's goal is to prepare the utilities for the next-generation grid, sometimes referred to as Grid 3.0, which will require more computing power and better software to process and analyze massive amounts of data, to forecast demand, and to meet that demand with supply from a combination of centralized, baseload power generation and distributed, intermittent power generation.

"With the existing management system designs, the software is still based on legacy concepts of mathematical processes and computation," Myrda said. "Our utility members are really challenged, and we are trying to bring everyone along the learning curve to develop these tools and make it clear to vendors what they will ultimately need to deliver."

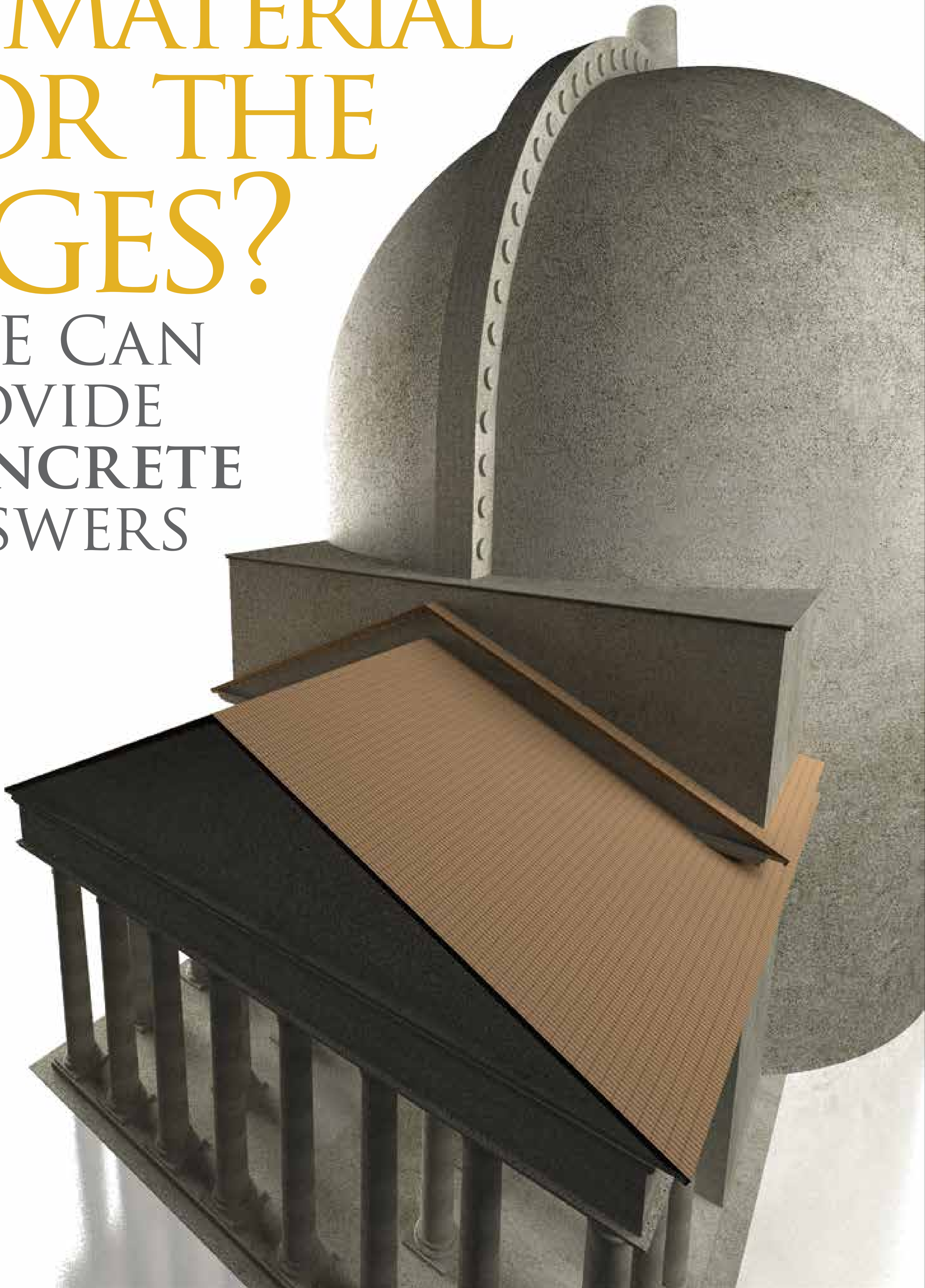
Some of the underlying resources needed for Grid 3.0 already exist. Supercomputers that use graphics processors for parallel processing are not rare animals. Software for collecting, analyzing, and storing data has become a hot area of technology development at companies such as Oracle and EMC, thanks to the explosion of Internet data from e-commerce sites and social networks. What utilities will need are applications that can build on such computing and database management technologies. "What we are doing is taking the various building blocks and connecting them to create innovative solutions for our industry," Myrda said.

This article was written by Ucilia Wang. Background information was provided by Paul Myrda, pmyrda@epri.com, 708.479.5543.

Paul Myrda, a technical executive, coordinates EPRI's Smarter Transmission System work and manages the transmission portion of the IntelliGrid program. Besides being involved in additional activities related to cyber security, he represents EPRI on the Industrial Advisory Board for the Power Systems Engineering and Research Consortium. Before joining EPRI, Myrda was director of operations and chief technologist overseeing planning and asset management functions for Trans-Elect Development Company. He holds B.S. and M.S. degrees in electrical engineering from Illinois Institute of Technology and an M.B.A. from Kellogg School of Management.

A Material for the Ages?

NDE Can Provide **Concrete** Answers



THE STORY IN BRIEF

The electricity industry's concrete structures serve a range of purposes in virtually every corner of the power landscape. EPRI research on concrete aging, quality, and monitoring and diagnostics can support informed decisions about the condition, maintenance, and repair of these structures, ensuring a strong prospect for continued service.

Concrete has proven its structural integrity for centuries. Rome's Pantheon, built circa AD 126 and featuring the world's largest unreinforced concrete dome, is still standing—a testament to the material's strength and durability. Today concrete is the foundation of many power industry facilities, but much of this electricity infrastructure, built 40 or more years ago, is showing its age. To ensure the continued integrity and long life of these assets, it's necessary to limit concrete degradation in existing structures and improve the quality of concrete in new construction. EPRI is conducting research to better understand and monitor concrete conditions—an effort that will provide insight into the health of older structures and the integrity of new ones.

How Concrete Is Aging

The electricity industry relies on concrete for a broad range of structures: cooling towers, nuclear containment buildings and the reactor cavities they enclose, spent fuel pools, wind turbine foundations, hydroelectric dams, transmission tower pedestals, underground vaults, flue gas desulfurization units, and water treatment basins. As these structures age, the concrete can undergo some deterioration. While concrete has a solid track record overall, EPRI is pursuing initiatives that can help utilities assess the health of their concrete assets and decide whether aging structures should be repaired, enhanced, or replaced.

Problems at some facilities have been traced back 30 to 40 years to lapses in initial quality control. For instance, several U.S. nuclear plants have had to address liner corrosion resulting from gloves, wood, and brushes being embedded in the concrete when it was poured. "Much of the degradation is caused by poor construction practices, but design deficiencies and outdated operational and maintenance practices also can damage the concrete," explained Maria Guimaraes, a project manager in EPRI's Nuclear Sector.

In the past four decades, scientists have developed a much greater understanding of how concrete ages. With better assessment techniques and more potential solutions available, new inspection and monitoring efforts are enabling remedies to be applied more effectively.

Concrete composition and use vary widely across the power industry, limiting the effectiveness of single-concept assessments and solutions. Either of concrete's main components—the cement or the aggregate material—can degrade, as well as the embedded steel rebar that reinforces it. The materials (even the water) used to make concrete can vary greatly from region to region as well. And problems can be caused by a great variety of processes: prolonged, acute exposure to high temperatures; freeze-thaw cycles, when water infiltrates the concrete, freezes, and expands to cause cracking; gamma and neutron radiation in nuclear plants; carbonation, where atmospheric CO_2 permeates the concrete; mechanical damage, which can crack, erode, or wear down concrete; and various chemical reactions.

In-depth understanding of the condition of concrete informs decisions to repair or replace. In the past, engineers and inspectors relied on cumbersome manual inspections to assess concrete condition. EPRI is looking at several nondestructive evaluation (NDE) methods that can do quicker and less costly inspections of vertical structures, monitor the quality of freshly poured concrete, and detect corrosion, pattern cracking, and single defects such as vertical cracks. But developing effective NDE techniques for concrete has been challenging.

Robotic Inspection of Existing Plants

Accessibility can be a real challenge for concrete inspection. Cooling towers, hydroelectric dams, and nuclear containment buildings are large, curved vertical concrete structures that have required labor-intensive manual inspections involving the use of extensive, hard-to-manage temporary scaffolding. Automated, robotic approaches could be safer, faster, more efficient, and less expensive, allowing inspections to be performed more frequently.

While existing robotic vehicles could conceivably have been modified to perform these inspections, none of them was well suited for large vertical structures. EPRI sought proposals for robotic inspection technology that is

- rugged enough for outdoor deployment;
- equipped with enough battery or independent power to operate for four days;
- flexible enough to carry a variety of inspection devices to detect different types of flaws; and
- able to traverse rough surfaces.

EPRI analyzed a range of robotic inspection ideas submitted in response to its request, including an electro-adhesive wall-climbing robot (think Spiderman) and a remote-controlled vertical takeoff and landing vehicle (think helicopter). EPRI's choice for further evaluation was a concrete crawler designed to negotiate concave, convex, or overhanging vertical structures—including gaps, seams, and surface obstacles such as conduit—while carrying over 40 pounds of equipment. The crawler's vacuum chamber generates more than 225 pounds of adhesive force and is surrounded by a rolling foam seal that guards against leakage and facilitates propulsion. The adhesion is so strong that it would require more than 50 pounds of force to dislodge the robot from a smooth concrete surface.

As submitted, the crawler was essentially a remote-controlled climbing vehicle, lacking both a positioning system and the NDE devices that would allow it to perform inspections. EPRI evaluated examples of both missing components and selected two that could be fitted to the crawler. The selected positioning system can display the vehicle's location and previous path on the structure and may eventually provide more sophisticated and automated vehicle control, such as commanding the crawler to move to a specific location on the structure. EPRI chose a tetherless NDE device that transmits signals through open air for data collection.

A 2012 demonstration confirmed the effectiveness of the robot's three individual components, and a test is scheduled for 2013 at a hydroelectric dam to demonstrate the integrated operation and performance of the crawler, positioning system, and NDE device. "For hydroelectric dams, it is critical to maintain the integrity of concrete structures," said Stan Rosinski, program manager of EPRI's waterpower research program. "Robotic inspection will enhance integrity assessments while reducing risk to plant personnel, who generally perform such assessments using scaffolding or climbing harnesses."

EPRI is developing a lawnmower-sized "concrete crawler" robot to support the safe inspection of large vertical concrete structures in the electric power industry, such as hydroelectric dams, nuclear containment buildings, and cooling towers.

New Technologies Offer Continuous, On-Line Monitoring

Sometimes it is more effective to install permanent monitoring equipment than to rely on periodic assessments. A case in point is the Robert E. Ginna nuclear plant in New York.

The concrete walls of nuclear containment structures are reinforced with post-tensioned steel tendons. Ordinarily, the tension is verified with a costly, time-consuming test that determines how much force is needed to lift the "head plate" at the top of the tendons. If that amount of force falls below a particular level, the tension is considered insufficient, requiring the insertion of shims to reestablish the correct tolerance.

EPRI is involved in a pilot project at Ginna to test a tendon strain monitoring system that will collect information while the plant is on line. In place of the typical lift-off testing, fiber-optic gauges installed on the main shims supporting the head plates will provide continuous, real-time data on tendon load, strain, and temperature, which periodic lift-off testing can't provide. The fiber-optic system gives plant engineers baseline information on tendon condition and lets them track changes over time.

The system can also monitor and measure strain variation caused by seasonal or diurnal temperature cycles or other factors. For instance, the engineers ran a structural integrity test in which they pressurized the containment to simulate a coolant-loss accident, and the fiber-optic system was able to measure the increased strain on the tendons.

Quality Control in New Construction

Understanding degradation in aging infrastructure is important, but new infrastructure is being built every day; development of measures that improve the quality of concrete as it is being poured is a savvy investment for the future. EPRI is looking at ways to incorporate sensors into construction tools to make real-time quality assessments of fresh concrete, so that any needed repairs can be made before the concrete sets.

When concrete is poured into a form, variations in consistency and fluidity can trap pockets of air and create "honeycombs" in the concrete, particularly around rebar. To reduce these voids, the form is mechanically vibrated, much as a cake pan is shaken or tapped on the counter to release trapped air bubbles from batter. Since there are no clear acceptance limits for honeycombs and voids, any voids remaining because of poor vibration and consolidation can delay construction until appropriate remedies are determined and applied.

EPRI is examining the feasibility of integrating inexpensive technologies available in smart phones, combining them with a global positioning system, and then attaching them to a concrete vibrator to obtain the needed quality control for concrete vibration and placement.

This solution also involves installing NDE sensors in the concrete vibrators to detect whether anomalies exist in the concrete as it is poured, giving a "go/no-go" indication in real time. "Attaining that goal is critical," said Guimaraes, "because the lack of quality control during concrete pouring is one of the leading causes of aging-related degradation. Inadequate quality control results in weak concrete, which compromises the durability of the structure. A successful demonstration of this application will open the door for using this technology for concrete quality control activities in large construction."

Since unset concrete behaves much like a solid/liquid slurry, NDE methods already in use in the petroleum and geotechnical exploration fields may be adaptable to power industry application. Techniques that have demonstrated potential include time-domain reflectometry, which can detect the presence of voids in concrete by observing reflected electromagnetic waveforms; P-wave velocity measurement, which indicates variations in the speed of sound waves as they travel through concrete; electrical conductivity approaches, where electrical probes detect the presence of voids; and the use of gamma radiation to determine the density of fresh concrete. The next step is to scale up these tests in the field with the optimal NDE technique.

To take quality control even further, EPRI has compiled comprehensive guidelines that prescribe methods to prevent the onset of issues that have arisen during construction of concrete nuclear structures. One such problem is void formation in concrete near the bottom curved portion of reactor liners. Ineffective or excessive concrete vibration is the most common cause, but the voids can be prevented by increasing the fluidity—that is, the flow rate—of the concrete. In 2014, EPRI will start working on the use of fluid concrete (self-compacting concrete) in heavily reinforced areas.

To achieve the longest possible operating life for power plants, the electricity industry must learn more about the environmental conditions that degrade concrete structures. Measurement devices and construction methods that will improve the quality of new concrete are necessary as well. EPRI's research is paving the way so the power industry can enhance both old and new infrastructure.

This article was written by Ray Pelosi. Background information was provided by Maria Guimaraes, mguimaraes@epri.com, 704.595.2708.

Maria Guimaraes is a project manager in EPRI's Nuclear Sector, specializing in the aging and inspection of concrete structures. Before joining EPRI in 2009, she worked for Aalborg Portland in Denmark, developing new cements that have reduced CO_2 emissions. Guimaraes earned a Bachelor of Science in civil engineering from the Universidad Nacional del Nordeste in Argentina, a Master of Science in Civil Engineering from New Castle University, and a PhD. in civil and environmental engineering from Georgia Institute of Technology.

Check out a brief video report of a demonstration of the concrete crawler with an NDE payload at New York Power Authority's Niagara Power Project. www.youtube.com/user/EPRIvideos

Researching Concrete Health Across the Industry

Several additional EPRI research projects are probing existing concrete structures in the power industry.

Hydropower: EPRI is evaluating emerging nondestructive evaluation (NDE) techniques to improve the detection of damage in aging concrete. A concrete degradation matrix for hydropower assets is also being developed to serve as a field guide and a technical basis for inspections.

Wind Power: A recent EPRI study (1022113) identified durability of the wind turbine's concrete foundation as a critical concern for long-term operation of wind power facilities. The study recommended periodic targeted inspection of foundations and provided guidance on integrity assessment approaches. EPRI is evaluating coating options for concrete foundations that will self-repair surface micro-cracks.

Transmission and Distribution: To probe the extent of concrete degradation in substations, transmission lines, and switchyards, EPRI is surveying its members to collect data on visual examinations and destructive and NDE tests. The results will be used to identify research needs for advanced repair, replacement, and inspection techniques. EPRI has also developed a new field guide that addresses the inspection of transmission line foundations.

Nuclear: The effects of radiation and temperature on concrete are being investigated in a collaborative project with the U.S. Department of Energy. For example, because leakage beneath the liner has degraded concrete in the spent fuel pools at some nuclear plants, EPRI is exploring the rate at which water containing boric acid affects the structural integrity of those pools. Guidelines for dry cask storage structures are being developed to cover inspection, prevention, and repair methods, as well as identification of degradation mechanisms.

R&D Quick Hits

What to Do in Emergencies: Get Social

Utilities are recognizing the value of social media and how they can improve a company's engagement with customers. Research shows that the majority of utility Facebook and Twitter accounts are used for education and outreach. Nearly a quarter of utility companies use Twitter for outage management and emergencies. Consolidated Edison and PSE&G use of social media during Hurricane Sandy have been favorably acknowledged; subscriptions to utility Facebook pages and Twitter feeds soared during the storm, and utilities are working now to sustain the public's engagement with these new media.

EPRI organized three workshops for 2013 to gain insights into the use of social media before, during, and after such events as Sandy. Workshop topics include the following:

- Ways utilities on the operations side are using data obtained via social media to improve situational awareness and response during disturbances
- Opportunities for customer communications, as well as for integrating customer-generated data into existing utility systems
- Potential research needs and opportunities

The New York City workshop, hosted by EPRI and Consolidated Edison, has already provided insights for using social media in communications. Typical activities include broadcasting advisories, communicating outage status, and delivering vital safety information. It is effective to use the media to alert customers about what to expect as storms approach, and it is important to keep the message consistent. Challenges include verifying the accuracy of data and information, consolidating the outage and damage data collected, and integrating social media data into a visualization platform.

A summary report of the workshops' key findings will be released in fall 2013.

Solar Fact Book Shines

Commonly requested information on photovoltaics and concentrating solar thermal power is available in EPRI's *Solar Power Fact Book* (1024000), now in its third edition. Building on and complementing the annual *Renewable Energy Technology Guide*, quarterly market updates, and other EPRI resources, the Fact Book compiles a spectrum of expert-vetted data and information in an easily accessible format, avoiding overly optimistic claims sometimes cited by advocacy groups. System planners and others considering capacity expansion will find the book's data and graphics valuable for evaluating power purchase options, developing renewable energy technology and climate mitigation strategies, and communicating with the public about solar generation options.

A Concept Both Wide and Deep: Analysis Brings Focus to Sustainability

EPRI's Energy Sustainability Interest Group conducted an analysis identifying which aspects of sustainability the North American power industry considers the highest priority for the coming five years. EPRI based its analysis on a review of the current literature, a series of stakeholder interviews, and an electronic survey of 134 power company managers and 160 stakeholder representatives from government, private sector, nonprofit, environmental, and academic organizations.

Grouping responses under three "pillars" of sustainability concern—environmental, social, and economic—the study identified 15 issues considered to be most material to the industry near term. Three issues are expected to grow substantially in importance over the next five years: greenhouse gas emissions, water availability, and skilled workforce availability.

The study results indicated that sustainability is a top or very high priority for more than 58% of the utilities surveyed, with primary motivations related to core values of the organization (71% of companies), corporate reputation (67% of companies), and management of regulatory or operational risk (66% of companies). The report (3002000920) can be downloaded directly from the EPRI website, www.epri.com.

The Matrix: Reliability Reloaded

EPRI has more than 1,000 equipment reliability products available for nuclear plant operations and maintenance. The volume and variety of these offerings makes it a challenge to find the product appropriate for a specific issue. EPRI has simplified the search with a color-coded matrix that enables maintenance engineers to home in on a fix according to the type of concern—say, performance monitoring or corrective action—and the component of interest. Clicking on a green box in the matrix brings up an abstract of a product currently available. The user can download the product directly from that screen with an additional click. Yellow boxes indicate offerings under development. The matrix, available at http://ermatrix.epri.com, is updated continuously, with yellow items going green as they are published.

Without a Trace (Metal): Treatment Shown Effective for FGD Discharge

Wet flue gas desulfurization (FGD) effectively reduces SO_2 and other acid gases in fossil fuel plant emissions, but the process can also capture trace metals and metalloids that must be removed from FGD wastewater prior to its discharge to the environment. Such selective removal of trace contaminants has proved a challenge for the industry.

Results from an EPRI five-month pilot test (1022161) confirm that the hybrid zero-valent iron (hZVI) process can effectively capture selenium, mercury, and various other trace metals from FGD wastewater. Building on laboratory and bench-scale success, the pilot-scale system was able to treat effluent at 1–2 gallons per minute, reducing total selenium to less than 10 parts per billion and total mercury to less than 12 parts per trillion.

In pursuing the technology's application at full scale, the project provided researchers with operational experience and the ability to estimate basic operation parameters, optimize reactor and process design, develop a solid waste management plan, and evaluate the process economics of the hZVI technology. The results have cleared the way to begin a 50-gallon-per-minute demonstration in 2013 at the Water Research Center in Cartersville, Georgia.

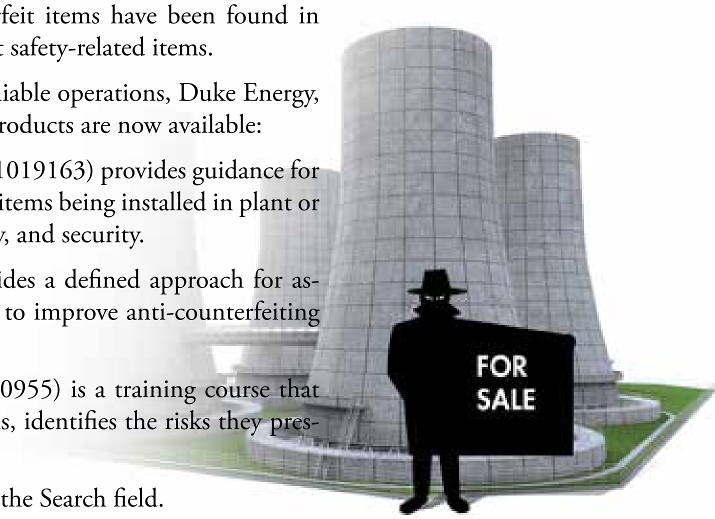
Countering Counterfeits: Products Offer Ways to Get on the Same Page

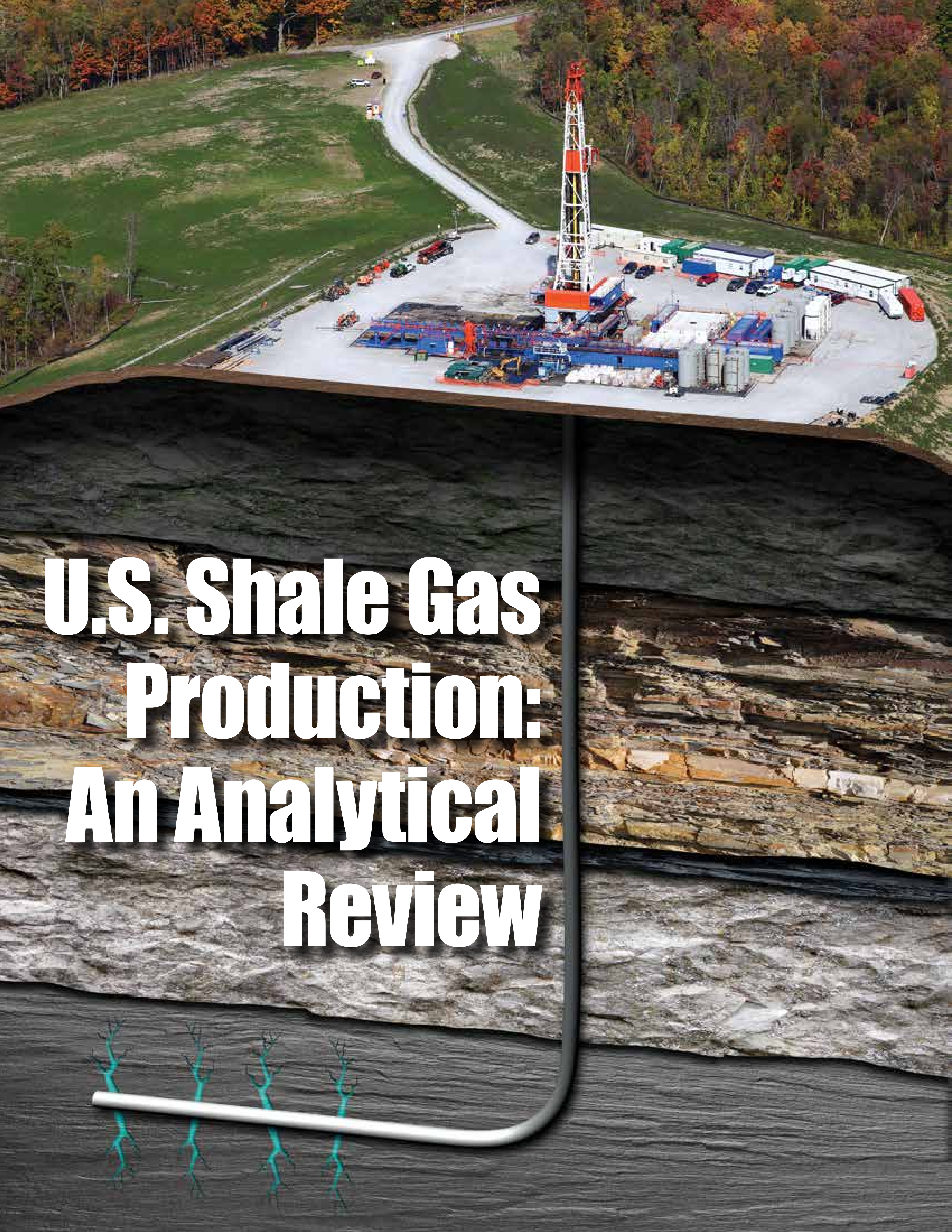
What do purchasers of designer handbags, baseball caps, and nuclear power plant components have in common? The need to be vigilant for counterfeits. Around the world, fakes and knock-offs have been found in military, industrial, and other critical infrastructure. While no known counterfeits have been installed in safety-related applications in U.S. nuclear power plants since the early 1980s, some counterfeit items have been found in nonsafety-related systems, and some plants outside the U.S. have reported suspect safety-related items.

Recognizing the need for new defenses against counterfeit parts to ensure safe, reliable operations, Duke Energy, SCANA, and Dominion teamed with EPRI to address the challenge. Three key products are now available:

- *Counterfeit, Fraudulent, and Substandard Items—Mitigating the Increasing Risk* (1019163) provides guidance for implementing enhanced controls to reduce the risk of counterfeit or fraudulent items being installed in plant or nonplant systems that could impact areas such as maintenance, personnel safety, and security.
- *Counterfeit and Fraudulent Items—A Self-Assessment Checklist* (1021493) provides a defined approach for assessing existing anti-counterfeiting measures and for identifying opportunities to improve anti-counterfeiting measures in existing processes and programs.
- *Computer-Based Training: Counterfeit, Fraudulent, and Substandard Items* (1020955) is a training course that describes counterfeit, fraudulent, and substandard items in nuclear applications, identifies the risks they present, and describes actions that can be implemented to reduce risk.

For more information, go to www.epri.com and enter the product ID number in the Search field.





U.S. Shale Gas Production: An Analytical Review

Natural gas reserves in the lower 48 states have been estimated at about 1,900 trillion cubic feet—enough to last 75 years at present production rates. About 30% of this gas is contained in shale formations, which are unlike conventional natural gas reserves. Shale gas is trapped in tight, impervious rock. Until recently, extracting gas from these formations was not economical; advancements in horizontal drilling, starting in the late 1990s, and high-pressure fracturing techniques (see sidebar, page 22) have changed that picture, bringing controversy along with them.

Production of natural gas has increased fifteenfold since 2000 and could triple from 2009 rates by 2035. This abundance of natural gas, and current low prices, could not have come at a better time for electricity generating companies facing tightening environmental regulations on coal-fired generation. But uncertainty surrounding the environmental impact of shale gas extraction, potential costs of production, and political considerations could lead to gas price volatility.

To help inform decisions regarding the use of shale gas for electricity generation, EPRI has led a comprehensive review of the available environmental data and research on shale gas, including the release of greenhouse gases and other pollutants, water use, the risks of spills and contamination, fluid disposal options, and economics. The study includes recommendations for best practices and identifies additional research and assessment needs.

The findings are cautiously optimistic. "We found no impacts that are complete showstoppers for shale gas production in the United States from an economic or environmental standpoint," said Sarah Jordaan, who oversaw the review during her tenure at EPRI. "That said, there are still uncertainties and unknowns that warrant additional research to ensure that environmental and economic risks will continue to be well vetted and mitigated."

THE STORY IN BRIEF

The surge in shale gas exploration has spurred tremendous interest in the processes, environmental implications, and economics of well production. To inform stakeholders and the public on these issues, EPRI has performed a comprehensive review of existing data and research on the benefits, challenges, and uncertainties of shale gas production.

Air Emissions

As an electricity generation fuel, natural gas has environmental advantages over coal because it burns more cleanly and releases less carbon dioxide; increased natural gas use has helped reduce carbon dioxide emissions from electricity generation to the lowest levels since 1992. A well-to-wire life-cycle assessment yields a more complex picture, however. Methane—the primary component of natural gas—is a more potent greenhouse gas than carbon dioxide, and leakage of too much methane at various stages of production, processing, and transport could potentially offset the emissions benefits of using natural gas.

The literature review confirmed that a variety of technologies can be applied to minimize leakage throughout natural gas systems. Best practices for well development include a procedure known as green completions, already in use by partners in the U.S. Environmental Protection Agency's Natural STAR program, which involves bringing in portable equipment that captures gas that would otherwise be vented or flared. Along with other "golden rules" proposed by the International Energy Agency, these practices add approximately 7% to the cost of drilling and completing a single well but could save money from reduced gas loss.

Diesel-powered machinery is also a factor. Used for everything from road construction and vegetation clearing to gas compression for distribution, this equipment emits additional carbon dioxide that contributes to the greenhouse gas total. While such emissions also occur with vehicles and engines at conventional natural gas wells, shale gas operations entail additional sources, including the trucks that deliver water and remove recovered liquid and the machinery used in fracturing. Air emissions can be reduced by electrifying much of the machinery that currently uses diesel or other liquid fuels; power to drive these cleaner options can be delivered to field locations via portable, skid-mounted transmission equipment.

In addition to greenhouse gases, natural gas (as well as oil) operations also generate volatile organic compounds (VOCs), nitrogen oxides, particulate matter, and hazardous air pollutants. Again, most of these emissions come from diesel-powered equipment, although VOCs can also originate in the well, especially when the well contains liquid hydrocarbons in addition to gas. The EPRI review found that these emissions are unlikely to be problematic for the health of nearby populations but that they could contribute to regional ozone formation.

While the current literature implies that air emissions from shale gas operations can be easily managed, the methods used to estimate emissions in the various studies are inconsistent and often use differing assumptions about the efficiencies of processes, the viable life of a well, the total

Obtaining Shale Gas

Shale gas formations, generally found deeper underground than conventional natural gas reserves, are often situated as far as 10,000 feet below the surface. In the United States, the bulk of the gas is contained in 14 major shale plays—geographical areas considered to be good bets for exploration—ranging in size from 1,200 square miles for the smallest to 77,671 square miles for the Marcellus Formation in the Northeast.

The thinness and breadth of typical shale layers has led to the adoption of horizontal drilling. This technique allows the well to be drilled vertically to the depth of the formation, at which point the bore is redirected horizontally to penetrate as far as a mile into the shale deposit. In some locations, ten or more of these horizontal wells can be drilled from a single surface pad, boring into the shale in different directions.

After the horizontal well has been drilled, the shale is cracked by a hydraulic fracturing process to increase its permeability and allow more gas to flow from the formation. The fracturing fluid—typically 98%–99% fresh water and crystalline silica sand—is pumped into the well under pressure to initiate the cracks, which spread radially as far as 1,000 feet from the well bore. The sand lodges in the cracks and holds them open for gas passage after the liquid is recovered and either reused or disposed of.

amount of gas available, the ratios of liquid hydrocarbons to dry gas in wells, and the effectiveness of technologies and practices used to prevent emissions. Emission characteristics also depend on the geology of the formation, and results cannot be generalized from one shale formation (or play) to another.

Water Concerns

Water has been at the center of most of the controversy over shale gas production. Concerns include the amount of water used, the chemical compositions of liquids, the ways these liquids are disposed of after use, and the potential for contamination of groundwater, surface water, or soil.

Hydraulic fracturing requires large volumes of water. For each well drilled, upwards of 200 tanker trucks deliver 3 million to 8 million gallons of water to the site. This water is used consumptively; that is, it can rarely be returned to the local water supply for public use.

While many parts of the Midwest and South depend on groundwater for a substantial part of their total water use, a county-by-county assessment showed that the shale plays and projected well locations for the most part fall outside those regions. With a few exceptions, water needed for fracturing was less than 1% of existing water use. Nevertheless, groundwater availability and use need to be evaluated for local impact before drilling is conducted in a specific location. Most states have regulations limiting water consumption, and these can affect water availability for fracturing operations.

The composition of fracturing fluids is also a major environmental point of discussion. They consist primarily of water (85%–90%) and crystalline silica sand (9.5%–13%). About 0.5%–2% of the fluid is made up of chemical additives that help to initiate cracks, dissolve minerals, reduce friction, facilitate flowback of liquid, and protect against corrosion, bacteria, and scale (salt buildup in the well that can develop in highly saline formations). If a fracturing fluid spill were to occur and not be adequately contained, it could cause environmental harm or require remediation.

Flowback liquid—the injected water recovered after fracturing—carries out with it clay, silt, metal, and hydrocarbons from the formation itself. In addition, well development requires removal of the salty water that was already present in the shale formation—a liquid called produced water. Depending on location, produced water can contain high levels of total dissolved solids, barium, calcium, iron, magnesium, dissolved hydrocarbons, and naturally occurring salts and radioactive materials. Many options exist for treating produced water, but multiple treatments are usually needed to handle the variety of contaminants. As a result, deep reinjection of produced water is almost always the most economical disposal method.

Preventing spills and leaks is an important concern for all oil and natural gas operations, and the risks of blowouts, well casing failures, and spills of machinery fuel in shale gas operations are the same as for conventional gas wells. With shale gas, the large volume of fracturing fluids, flowback, and produced water presents additional risks, which can be reduced with improved practices. For example, producers can store fluids in closed-loop steel tanks and piping systems instead of in lined open-air pits, or they can line well sites to minimize spill impacts. Best practices include detailed response plans and worker training in how to prevent spills and take countermeasures in emergencies.

The U. S. Department of Energy has developed less toxic additives for use in fracturing fluids, but some of the most toxic substances are often in the produced water, the composition of which is outside operator control.

Reusing flowback and produced water when fracturing new wells can trim freshwater consumption and lessen disposal issues. This approach has lowered fracturing costs in Pennsylvania's Marcellus Shale, where geological considerations limit options for deep-injection disposal.

Another concern is that the cracks created by fracturing might allow natural gas and fracturing fluids to migrate into private well and surface waters. One complication is that these gas wells often contain methane and other chemicals even before drilling begins. Before-and-after tests should be conducted on water wells at future drilling sites to resolve questions about contamination.

The literature shows that underground water injection can, under some circumstances, induce seismicity. The risk is low for gas wells, but high injection rates at disposal sites can trigger tremors if a fault already exists nearby that is in a near-failure state of stress. Limiting injection rates is a preventive mitigation practice.

Economics and Regulation

Determining the profitability of a shale gas well can be challenging, requiring break-even analyses specific to the resources and development costs of each play. The number of wells that can be drilled from each drilling pad is a key consideration, along with geographical location, reservoir pressure, depth of drilling, local water availability, and costs of wastewater transport and reinjection. Increased electrification, innovative approaches to environmental compliance, and adoption of best practices can improve economics, as can site-specific opportunities such as coproduction of natural gas liquids and crude oil. Accurate profitability projections will require better estimates of total production over the life of a well.

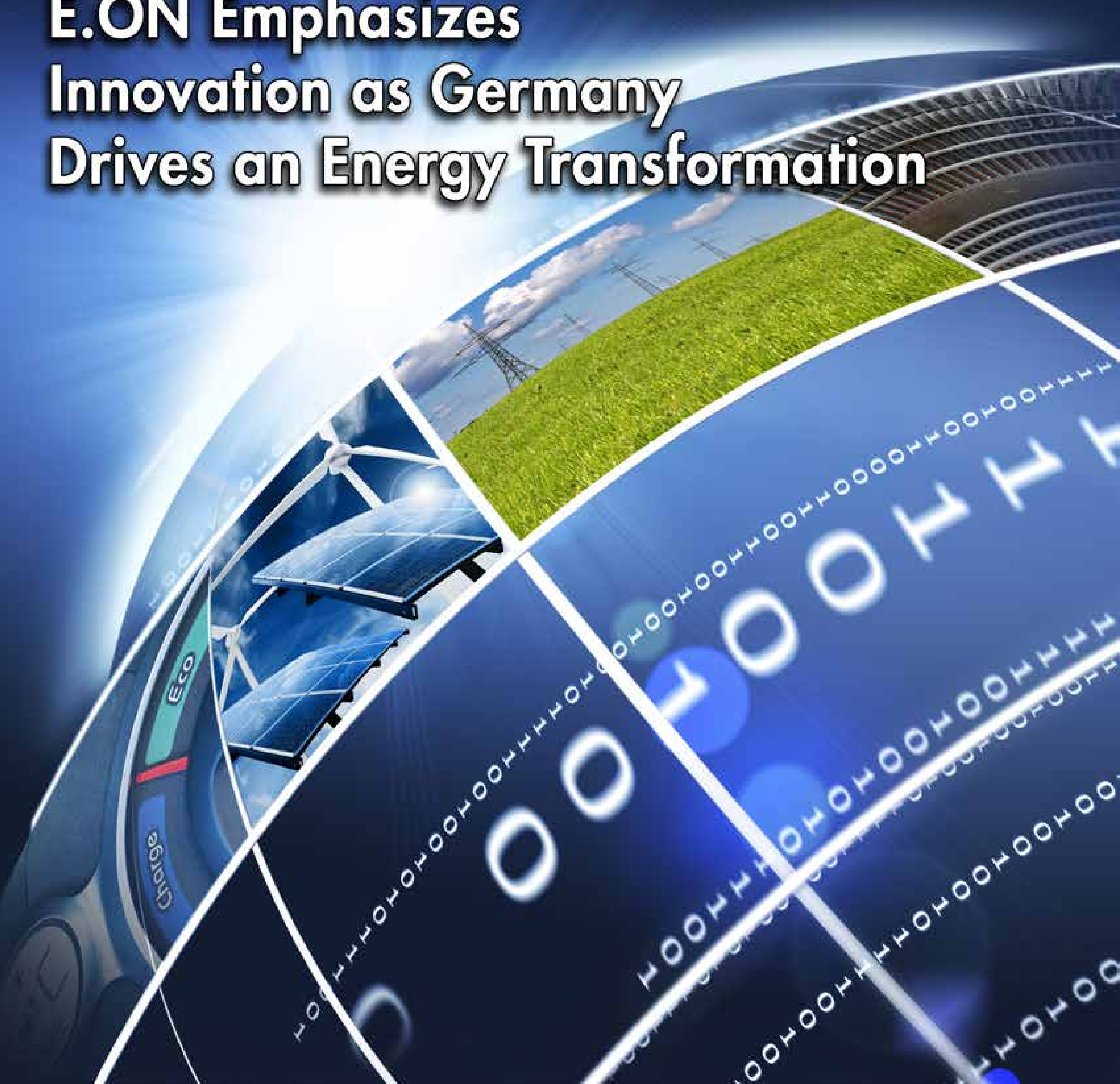
Several emerging issues could have substantial effects on shale gas economics. For example, the cost of seismic monitoring to test for faults near hydraulic fracturing operations or reinjection sites has not been closely examined. In addition, data suggest that the cost of reclamation—capping a used well safely and returning the land to a natural state—is much higher than expected. As a result, many well operators abandon used wells, forfeiting cheap, undervalued permit bonds, to avoid paying for reclamation. States are passing new laws to make well operators clearly liable for land reclamation.

As Jordaan pointed out, shale gas production is a relatively fast-developing energy option, requiring better data on both environmental and economic fronts. "An important goal is to develop more consistent research methods with clearly defined pollution source categories and accurate estimates of emissions," she said. "More site-specific studies are needed, because it is difficult to generalize from one area to another. For water quality, the chemical composition of produced water needs to be better characterized by location. These are just a few of the many areas where ongoing study is needed to gain a better understanding of the environmental impact of shale gas."

This article was written by Cliff Lewis. Background information was provided by Sarah Jordaan. For more information on the project, contact Andrew Coleman, acoleman@epri.com, 650.855.8971.

Energiewende

E.ON Emphasizes Innovation as Germany Drives an Energy Transformation



Urban Keussen is E.ON's Senior Vice President for technology and innovation. The global utility's German operations are at the heart of a bold move to change fundamental aspects of grid operations, emphasizing renewable generation and creating momentum for a system that will rely on energy storage, distributed resources, smart technology, and new business models. Keussen spoke with *EPRI Journal* about some key challenges and approaches the company is taking to technological innovation.

EJ: Germany's Energiewende, or energy transformation, has brought a lot of attention to E.ON's shift to renewable energy. Subsidies, feed-in tariffs, and the shift to distributed resources are having big impacts on technology and grid operations. How do you describe the major changes that have come to Germany's electrical system, and what do they mean for your customers and for E.ON?

Keussen: The main change we see is driven by three things—policy and regulation, customer behavior, and technology development. The system where generation follows demand has been significantly changed. Today we have a peak load of about 80 gigawatts and installed capacity of wind and solar of more than 60 GW. We have a system where more and more the generation depends on wind and sun and not on demand. That is a 180° shift, where we have an overcapacity of renewables in the system, and we are trying to understand what we can do on either letting demand follow generation or using smart home technology at customer sites or electricity storage to deal with the volatility of the generation.

This leads to a number of challenges for customers. First, they have to pay more because of subsidies for the renewables. Energy is high on the agenda of public discussion. People are more and more what we call "pro-sumers"—that is, they produce and consume. Hundreds of thousands of customers have their own rooftop PV [photovoltaics], so the involvement of the customer is totally different than it was 5 or 10 years ago. Customers care about CO_2 emissions and green electricity, and they care about being more independent and having their own generation—one of the drivers for certain customers to behave in certain ways.

For utilities, having large-scale generation, transmission, and distribution, and supplying customers—the old business model—is eroding. More types of generation are owned by other stakeholders, which changes the business model, with utilities looking more to customer service and smaller-scale solutions.

"People are more and more what we call 'pro-sumers'—that is, they produce and consume. Hundreds of thousands of customers have their own rooftop PV [photovoltaics], so the involvement of the customer is totally different than it was 5 or 10 years ago."

With the highest density of photovoltaics in the world and more than 60 GW of wind and solar, we need thousands of kilometers of grid extension. A regional overload of the grid driven by increased renewable energy challenges us to operate the grid at the edge of capacity.

EJ: So the customer has an economic role—and not just as a consumer. Would you say that the customer's role in changing the system and the business model is primarily economic, or is it also social and political?

Keussen: It's both, and it depends. In Germany, we have people with a strong political role looking for low CO_2 emissions and green electricity, and we have groups more concerned on the financial side. For instance, a typical household pays about 28 Euro cents per kilowatt-hour, which is about 36 U.S. cents, and 5 Euro cents of this is a subsidy for renewables, and the subsidy is still increasing. There are more concerns that people with low income will have difficulty paying their electricity bills.

EJ: Given what you have seen in Germany to date, how far do you think the power systems will ultimately move toward a decentralized or distributed model?

Keussen: Things will definitely move in

"It's not that large-scale generation will disappear, because we need it as a backup system, but the mechanisms need to be different to reimburse large-scale generation."

that direction. It's not that large-scale generation will disappear, because we need it as a backup system, but the mechanisms need to be different to reimburse large-scale generation. For rooftop PV in Germany, you can produce electricity at about 19 Euro cents per kWh, while the cost for electricity taken from the grid is about 28, which includes taxes, grid tariffs, and so on. This has created a disruption to the overall system, and it's why we believe there will be a strong push for renewables. I believe the cost for PV will further decrease, driven by innovation, and PV will become more and more competitive, even compared with existing generation technology.

EJ: Do you see that subsidies, feed-in tariffs, and emissions mandates will continue to drive the evolution of the system and the technology innovation?

Keussen: Partly, yes. There's a debate in Europe on the feed-in tariff system, but there are so many people benefiting from it—all the investors—that I do not see the government taking this away completely, even though it's by far not the most efficient way to support renewables. On the CO_2 emissions system, you may know that the European emissions system is really not working; we have a price of about 4 Euros per ton of CO_2, which means a lignite coal plant emitting a lot of CO_2 runs, while more efficient, gas-fired plants are out of the money.

EJ: So it will be necessary to rationalize the systems. Do you see market mechanisms being brought in to do this?

Keussen: This is the discussion a number of European utilities have started. I hope that we can bring more rationality into the discussion, but it will be a challenge.

EJ: Shifting gears, let's talk about E.ON's venture capital approach, or what you call strategic co-investment, to drive new technologies.

Keussen: The intention is to get access to technologies and business models of innovative start-up companies and to deliver their products to our customers. We started talking to venture capital and start-up companies. We learned they are very interested in cooperating with us because we supply about 34 million customers in Europe and can grant great access to the market and customers. We can create a win-win situation when we invest in the company and at the same time agree on how to deliver that product to our customers. This increases the value of the start-up, and we benefit from this by being an investor. Since the middle of last year, we've done three investments, and there are more to come. We look mainly at what we call the downstream area, and mainly in the U.S. and Europe.

"We learned they [venture capital companies] are very interested in cooperating with us because we supply about 34 million customers in Europe and can grant great access to the market and customers."

EJ: Looking at specific projects, the Falkenhagen project stands out, where you're using electrolysis to produce hydrogen gas to mix with natural gas as a form of energy storage. Are you testing the basic technology or its application at commercial scale?

Keussen: Because each component is more or less proven technology, we tested the system and started pre-commercial operations. It's still a technical demonstration, because the regulatory regime is not there to operate it on a commercial scale. We are the first company worldwide taking excess renewable power, transforming it into hydrogen, and mixing it with natural gas in the pipeline system—storing the electricity there. We are also looking at converting CO_2 to methane and mixing the two by this method to make synthetic green natural gas.

EJ: Looking at a more distributed power system, how important is large-scale energy storage for E.ON?

Keussen: It is a pillar in the whole discussion. Imagine your system relying 80% on renewables; you have to find a way for storing electricity, and we classify our storage devices in three categories. One is local storage—you may have it in the basement of your house, to store electricity from your rooftop PV. The second is regional storage, a need especially driven by local grid constraints. The third is storage on a wholesale scale, where you can store electricity not for just hours but maybe days or weeks. There we need chemical storage—for instance, the power-to-gas technology.

"The more decentralized generation you have, the more you need storage technology and the easier it is to talk about micro-grids. If a quarter of a city or a number of homes say, 'We want to become independent,' then it becomes more likely."

So you can use power to overcome local constraints in the grid, or you can use it for long-term storage of power and electricity. That's why we feel it can become an important component of the system. The issue today is that you still lack the incentives and regulatory regime to finance it, but we're preparing ourselves to be ready to deliver the technology the moment the regulatory environment is adopted.

EJ: There's discussion about "islanding" parts of the grid to operate somewhat independently. E.ON is doing some interesting work on a real island, Pellworm Island, where you're looking at renewable generation, energy storage, and smart grid applications for distribution, end use, and communications.

Keussen: This tests a combination of technologies and devices in an island mode. It's a perfect place to test it in a defined and disconnected environment. It's not that we believe this kind of island operation will be the standard operation of the future, but it's a great place to test it. We see that certain kinds of island modes could develop, even in non-island environments.

"We are the first company worldwide taking excess renewable power, transforming it into hydrogen, and mixing it with natural gas in the pipeline system—storing the electricity there."

EJ: Will it point the way toward new configurations in micro-grids or larger islands within the grid?

Keussen: The more decentralized generation you have, the more you need storage technology and the easier it is to talk about micro-grids. If a quarter of a city or a number of homes say, "We want to become independent," then it becomes more likely.

EJ: E.ON is devoting significant investment and attention to offshore wind. What is driving that, and what's the principal challenge with this technology?

Keussen: We are one of the big investors in offshore wind, with projects in the UK and in Germany. We are advanced in our understanding of offshore technologies. Offshore will especially play a role in countries where onshore wind energy is not much accepted, like the UK. Because it's more expensive than onshore, the biggest challenge is to decrease capital expenditures.

EJ: And it's probably safe to say that's a challenge with many of the technologies you're focused on?

Keussen: It's one of the key challenges. If you start with innovative technologies, it's normal that you have to support them—new devices are typically far too expensive in the beginning. Finally a technology will survive as what we call the winning technology, being not just the most suitable but also the most efficient technology.

EPRI to Study Storage of High-Burnup Nuclear Fuel

Improvements in nuclear fuel technology have allowed plant operators to substantially increase burnup levels—the amount of power extracted from the fuel—over the last two decades, now tapping almost twice as much energy from a given amount of fuel as before. While this practice is clearly good for operational economy, questions have been raised about storage of the fuel after it has been retired.

"While casks have been designed for high burnup levels, we've been storing predominantly low-burnup fuel up to this point," said Christine King, EPRI's director of nuclear fuels and chemistry. "The reality is that in the future, all of the spent fuel will be high-burnup, and we will need to demonstrate dry storage casks' ability to handle it."

To provide this assurance and help inform future regulatory and licensing requirements, the U.S. Department of Energy (DOE) and EPRI are beginning a five-year, $15.8 million project to develop a special dry storage cask that is highly instrumented to track conditions inside the cask over an extended period while it remains sealed. The nuclear power industry will contribute at least 20% of the total project cost.

Designing the Cask

Concern over storage integrity centers mainly around the mechanical properties of the fuel cladding. High fuel burnup generally results in increased oxidation, higher fuel rod internal pressures due to increased fission gas release from the fuel pellets, and consequent higher stresses. A combination of these factors may cause deterioration, deformation, or—in extreme cases—even rupture of the cladding.

The demonstration unit will be a modified Transnuclear TN-32 dry storage cask, fitted with a specially designed lid to allow gas sampling and readings of temperature and other variables at a number of locations inside the cask. "We've done tests for separate degradation effects before, but with this full-scale, real-world testing, we'll be able to see if there are any cumulative effects across the storage system as a whole," said King. "Having realistic numbers and being able to develop a thermal profile across the full cask as the fuel cools down will tell us a lot about what's really happening in there and what the margins of safety are."

A Plan for the Future

EPRI expects to develop a draft test plan for the demonstration by August, followed by a public comment period. The final plan is to be complete by the end of the year. Activities for 2014 through 2016 will focus on designing the instrumented lid, obtaining a license for the modified TN-32 cask, identifying the fuel rods to be included in the test program, procuring the cask, and conducting a dry run. The target date for loading fuel into the instrumented cask, which will be stored at Dominion Virginia Power's North Anna site, is mid-2017.

The project is part of a new strategy by DOE to firm up the back end of the nuclear fuel cycle in light of delays in development of a permanent repository for spent nuclear fuel. "It's clear that the industry will be depending on dry cask storage technology for the foreseeable future," said King. "It's crucial that the technology move in step with the types of waste actually being produced now and in the coming decades, and that means a sharp focus on high-burnup fuels. The demonstration can confirm that today's designs are up to the task and perhaps suggest opportunities for future refinement."

To this end, the demonstration will benchmark the predictive models and empirical conclusions developed in earlier, short-term laboratory investigations on aging of storage cask components and will build confidence in the ability to predict cask performance over long periods. Information from the project could also be used to inform future regulatory actions associated with transportation and storage of high-burnup used fuel. It is expected that DOE will issue follow-on contracts to cover an extended, 15-year test period, with a total lifetime cost of the research in the $31 million range.

For more information, contact Christine King, cking@epri.com, 650.855.2164.

Visualization and Situational Awareness

Situational awareness is critical for grid operators to maintain reliability and minimize major system disruptions. The emergence of large regional electricity markets and the rapid growth of variable generation resources, without a corresponding growth in transmission infrastructure, create stress on transmission systems and introduce challenges for control centers. As a result, systems will be operated closer to operating limits, requiring careful attention to maintaining sufficient reliability margins.

To meet this challenge, the North American Electric Reliability Corporation (NERC) developed the concept of boundary conditions to derive real-time operating boundaries and margins that help system operators understand three basic considerations: the operating point (where we are now), the security margin (how far we can go), and control actions (what we should do).

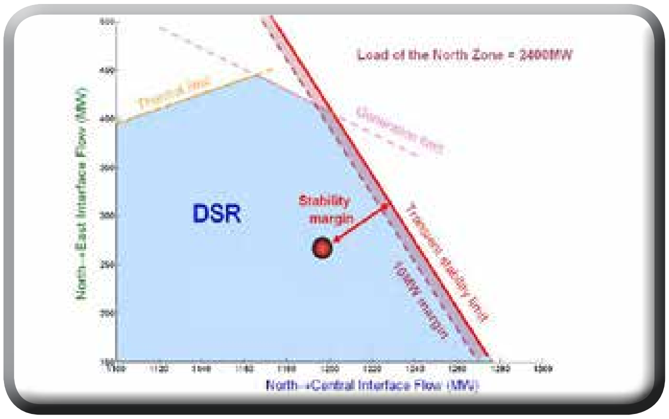
To optimize the development and use of this concept for today's increasingly complicated power grid, EPRI has reviewed state-of-the-art techniques for computing and visualizing operating boundaries, has identified remaining technical gaps, and has developed functional requirements for an online tool that will allow operators to comprehensively visualize operating boundaries (1021924).

Interpreting Diverse Data

Power utilities currently apply power system security assessment tools to simulate credible contingencies on a daily or even hourly basis in order to identify potential security violations. Most boundary and margin information is drawn from energy management system (EMS) data or directly from the security assessment tools. The challenge is in how to interface with, interpret, and present these data to operators in an effective, meaningful way, highlighting information critical to boundary/margin decisions without distracting the operators with inconsequential data.

The difficulty is complicated by the variety of factors involved in grid security. So far, few control center applications can provide effective online visualization of security criteria such as steady-state thermal limits of transmission lines, steady-state generator VAR (volt-ampere-reactive) limits, limits on control devices such as capacitor banks and transformer taps, steady-state bus voltage limits, small-disturbance stability limits, voltage stability limits, and transient stability limits.

Effective visualization tools that integrate displays of crucial real-time boundary and margin information will help operators manage a power system with acceptable performance under credible contingencies, protect system equipment from damage, and restore the system after a blackout.



The dynamic security region (DSR) approach allows grid operators to visualize stability margins by observing the position of the operating point within a boundary that defines secure operation.

Tools for Data Analysis and Visualization

A review of analysis techniques led EPRI to propose the dynamic security region (DSR) approach for further development. The approach outlines a dynamic set of feasible operating points, at which the system will maintain transient stability after contingencies arise; the boundary of a DSR, presented graphically, can indicate an approximate real-time operating limit under fault conditions. EPRI successfully validated this approach on several power systems, including one of the largest in Southeast Asia. Several other concepts were also investigated, including an iterative optimization–based approach, a singularity-based approach, and a data mining–based approach.

Further work is focusing on developing a tool for visualization of operating boundaries (VOB)—an easy-to-use display that can present the grid's operating boundaries in real time and help alert operators if the system state is too close to security boundaries with insufficient margins (1024256). The requirements include state-of-the-art interface designs, including animation of displays to indicate progressive changes in system conditions and aggregated views with the ability to drill down to highlight data for different levels and groupings of contingencies. Specifications were also developed for the VOB tool's system architecture, data requirements, control requirements, and boundary definition.

The VOB tool, including working displays, was successfully demonstrated offline on WSCC-179—a simplified model of the Western Electricity Coordinating Council system. Continued research will focus on further development and prototyping of boundary algorithms and a demonstration of the evolving visualization tool at member utility control centers.

For more information, contact Bob Entriken, rentriken@epri.com, 650.855.2198, or Daniel Brooks, dbrooks@epri.com, 865.218.8040.

Zeroing In on Boiler Cycling Damage

Increased cycling and flexible operation have introduced new reliability issues for baseload fossil fuel plants, as components and materials are subjected to temperature/pressure variances and stresses for which they were not designed. Although damage from cycling operation can occur throughout a fossil unit, boiler components are of particular concern.

The consequence of severe unit cycling is often not well understood by utility operators because of the number of complex effects, many of which can develop over months or years without detection. If there is no immediate component failure or obvious damage, plant operators might assume that a unit is robust and able to tolerate recurring, severe operating events when there is actually substantial unrecognized damage to the unit.

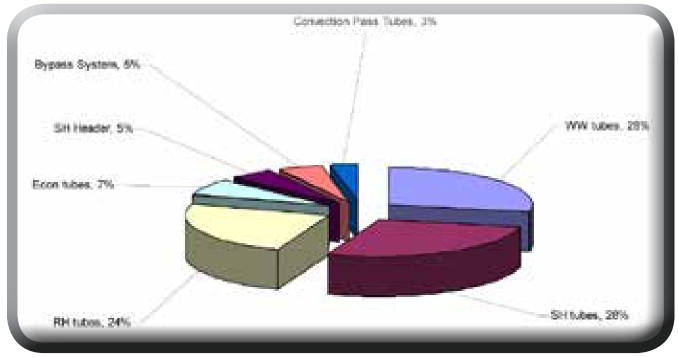
EPRI is looking to clarify problems and available solutions by identifying and ranking damage mechanisms and developing monitoring, modeling, and corrective actions that can reduce cycling-influenced boiler damage.

Damage Mechanisms

Plant cycling and flexible operation encompass a number of different firing regimes: brief operation above maximum continuous rating, low-load operation with return to normal-load conditions, and a variety of stop-start cycles involving hot, warm, or cold restarts. Each type carries its own complex concurrence of stress factors, and each is likely to require a different focus for damage avoidance.

For example, for relatively short shutdowns (less than 12 hours) followed by warm starts, detailed consideration needs to be given to pressure and temperature preservation and elimination of the condensate formed in the steam-touched components either during the shutdown or during the pre-start air purge. For longer outages, more emphasis should be given to the preservation of the stable protective surface oxides on the water-touched components and general atmospheric corrosion of the boiler components. For units that frequently experience low-load cycles, it becomes more challenging to maintain reliable performance and uniformity of the fuel air system, which can affect gas stoichiometry and other factors that control ash corrosion and slagging/fouling behavior.

In the first phase of the project, researchers made use of industry databases and information on some 122 specific fossil units to rank the boiler components most affected by cycling operation. The damage mechanisms most likely to be induced by cycling were then ranked for each boiler component through application of earlier EPRI research, detailed engineering judgment analyses, and a survey of experienced field engineers. The



For supercritical units, waterwall (WW), superheater (SH), and reheater (RH) tubes top the rankings for boiler components damaged by cycling operation.

two rankings were then used to create overall ranking tables of boiler component and damage mechanisms for subcritical and supercritical units. The tables, which include a discussion of the influence of cycling on the damage mechanism and methods for inspection and potential corrective actions, are available in *Damage to Utility Boilers by Cycling and Flexible Operation: Report on the State of Knowledge* (1023830).

Ongoing Work

In the second phase of the research, the rankings of components and damage mechanisms will be used to develop a theory-and-practice report that will help operators deal proactively with incipient boiler damage from cycling operation. The highest-ranking components and damage mechanisms will be discussed in extensive detail, and the report will present case studies that highlight occurrences where unit cycling has had a profound effect on a specific damage mechanism and component. The report will include detailed information on the following:

- The nature, features, and locations of cycling damage
- Damage mechanisms, including event sequences and impact ranking
- Root causes
- Diagnostic troubleshooting, monitoring, and instrumentation
- Modeling of damage extent and severity
- Repairs, immediate solutions, and mitigative actions
- Long-term actions to prevent repeated failures
- Possible implications for other parts of the plant

The proposed work will be done through an international collaborative program that will include EPRI and DOE.

For more information, contact Kent Coleman, kcoleman@epri.com, 704.595.2082, or Bill Carson, bcarson@epri.com, 704.595.2698.

Total Cost of Ownership for Plug-in Electric Vehicles

Over the past decade, hybrid electric vehicles have made a successful entry into the mainstream automotive world, with hybrids now offered by all major vehicle manufacturers and designed for virtually every model class, from small economy cars to pickups and off-road vehicles. Plug-in electric vehicles (PEVs), introduced more recently, face a similar market-entry trial, adding changes in fueling infrastructure and, in some cases, more restricted travel ranges to the mix.

As was the case with conventional hybrids, early assessment of PEV marketability has focused mainly on costs, with higher initial cost potentially offset by lower operating expenses. EPRI investigated this issue in a recent analysis of the life-cycle costs of two PEVs currently available for purchase—the Chevrolet Volt and the Nissan LEAF. The study (3002001728) compared both models with feature-matched conventional and hybrid vehicles and considered realistic driving patterns, two purchase options (cash up front and 60-month financing), government incentives, and projected financial discount rates.

While both vehicles are plug-ins, the LEAF is a battery-only vehicle, which limits driving range between charges. The Volt is an extended-range vehicle, whose battery is charged continuously by a small gasoline engine when the initial charge is depleted; this makes the Volt similar in usage to conventional hybrid vehicles. Cost assumptions for the LEAF include installation of a Level 2 EVSE (electric vehicle supply equipment) charging unit, which is a common option. The Volt is assumed to charge from a standard 120-volt outlet.

No financial value was estimated for less tangible PEV benefits, such as commuter lane access, home recharging convenience, vehicle repairs, and a smoother, more pleasant driving experience—all of which previous EPRI analyses have found to be important to potential vehicle buyers but difficult to monetize.

Study Results

The study concluded that with current incentives and prices, financial factors should not be a deterrent to a PEV purchase for most buyers. In terms of both total lifetime costs and monthly outlay, the Volt is within 15% of comparable hybrid or conventional vehicles. Because of the recent reduction in price of the Nissan LEAF, purchasing the vehicle can save consumers up to 25% over the lifetime of the vehicle. Because higher capital costs are well balanced by operating-cost savings, the decision to purchase a PEV can usually be made on the basis of personal values and preferences rather than financial limitations.

Chevrolet Volt *Nissan LEAF*

The analysis revealed that driving patterns have a significant impact on the relative benefit of a PEV versus conventional and hybrid vehicles. For example, battery-only PEVs like the LEAF are range-limited, making them more advantageous for shorter-range daily driving and less beneficial for longer-range driving—particularly where the vehicle charging infrastructure is limited. However, the relatively low capital cost and very low operating costs for the LEAF offer substantial overall cost advantages for well-matched drivers. There also appears to be large potential for customers to improve their ownership costs through behavior adaptation. For example, for two-car families, a LEAF might be used preferentially for around-town driving but not at all for longer trips.

Because the Volt can be operated in hybrid mode with roughly the same range and usage as conventional vehicles, the risk of a negative impact from driving patterns is low.

External Influences

Sensitivity analyses suggest that changes in gasoline prices will have a significant impact on the relative costs of PEV ownership but that state incentives or rebates and equivalent vehicle price changes will have an even larger impact on cost tradeoffs. The analyses indicate that capital and operating costs are reasonably well balanced at the current time for most vehicle comparisons. While changes in the price of gasoline could affect this balance, favorable state incentives or equivalent changes in capital costs for vehicles will have a larger impact than fuel prices and will significantly improve payback time, total ownership cost, and monthly expenditure.

For more information, contact Mark Alexander, malexander@epri.com, 650.855.2489, or Morgan Davis, mdavis@epri.com, 650.855.8724.

Sliding Pressure Reduces Heat Rate Penalties of Load Following

Most of the U.S. coal-fired plants currently in service were designed for baseload operation. Today, however, many of these units are operated in a continuous transient mode, following variations in generation demand and experiencing large changes in load throughout the day. This new mode of operation presents a myriad of problems for the aging fossil fleets, including detrimental effects on a plant's heat rate.

Operating a plant in sliding-pressure mode by lowering the turbine's throttle steam pressure during periods at reduced load can moderate the heat rate penalties associated with increased load following. To gauge the potential efficiency advantages of sliding-pressure operation, EPRI compared the heat rate values for a large coal-fired plant operating in constant-pressure and sliding-pressure modes during load following. The host unit, which began commercial operation in the early 1980s, was chosen to be representative of many units in the U.S. coal-fired fleet.

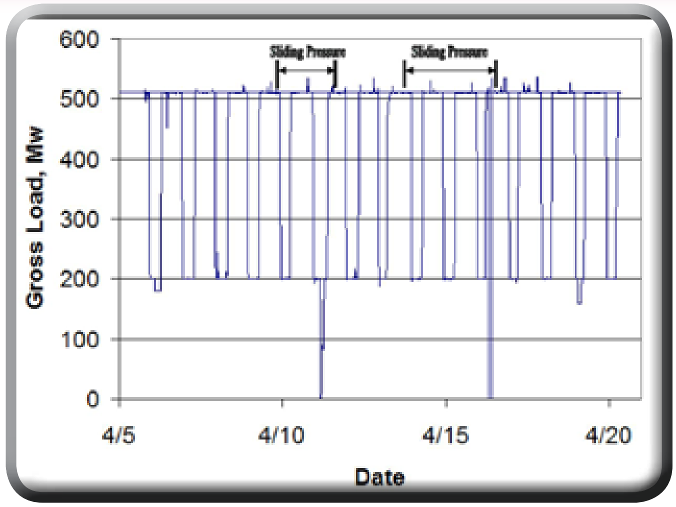
Data and Analysis

The study's 500-megawatt host unit consists of a Combustion Engineering tangentially fired boiler burning bituminous coal, a Westinghouse steam turbine with seven stages of feedwater heating, and an open cooling-water system. The plant's typical operating regime is characterized as steady full-load (510-MW) operation separated by intervals of steady minimum-load (200-MW) operation ranging from four to eight hours in duration.

The plant data were collected over two months, from March through May, 2012. During this period, there were 40 instances of load following, where steady operation was decreased from full load to 200 MW and then returned after a time to full load. Each load drop or increase entailed a 300-MW change in load, and there was no operation for an extended period at any intermediate load. The average ramp rate during a load change was approximately 5.5 MW per minute.

The unit operating data were evaluated to determine the load-following profile, the immediate effect on heat rate, the effect of sliding pressure as a coping mechanism, and changes in the cycle that resulted in improved heat rate performance. The data were processed using performance monitoring software that considered more than 150 key performance parameters characterizing unit operation and a sufficient number of points to calculate boiler efficiency, turbine cycle heat rate, and net unit heat rate. Data readings were taken at 10-minute intervals, with each time slice containing a complete snapshot of data.

The study findings indicated that the average turbine cycle heat rate and net unit heat rate both improved by about 2% when the unit was operated in sliding-pressure mode at low loads. The high-pressure turbine efficiency improved by 7 percentage points with sliding pressure—the most significant performance change under sliding-pressure operation.



Sample test load profile, showing sliding-pressure intervals

Boiler efficiency remained unchanged regardless of the pressure mode, indicating that the boiler operation was not affected by sliding pressure. Final feedwater temperature, main steam temperature, and hot reheat temperature each improved approximately 4° with sliding-pressure operation.

More Heat Rate Improvement Tools

Information on the sliding-pressure study is available in the final report, *Methods to Mitigate the Effect of Increased Cycling and Load Following on Heat Rate* (1023912). In addition, EPRI has recently released an updated edition of its *Heat Rate Improvement Program Guidelines* (1023913), a single-source document with the tools and information necessary for power plant staff to develop and manage an effective heat rate improvement program.

The updated version supplements earlier industry survey insights with sections on justifying, initiating, and maintaining a program, selecting measurement approaches, running baseline performance audits, and communicating results. Justification has become particularly important in recent years, keyed to both the market and the operation philosophy of the facility. In most cases, programs can be justified by reduced fuel costs, reduced air emissions, and the potential for improved economic dispatch of the unit.

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Research Expands to Examine Eel Migration and Hydro Dams

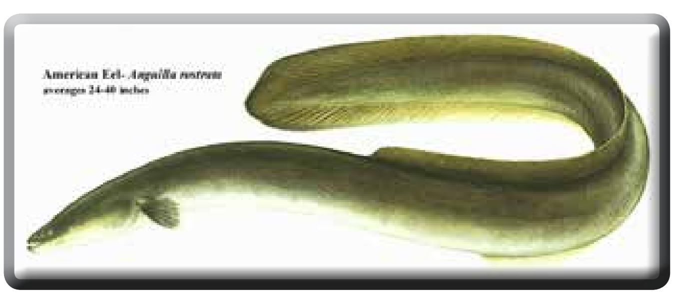
News reports on hydroelectric dams and fish migration typically focus on salmon, trout, and other common food and sport species. But less familiar fish, including the American eel, are of concern as well, with their reduced numbers prompting regulators to consider them for threatened or endangered status. Effective methods exist for passing eels upstream at hydroelectric dams, and resource management and regulatory agencies often demand it; however, downstream passage has proven to be far more challenging. Currently, there is no effective method to safely divert eels around large, operating hydroelectric facilities during their downstream migration.

Exelon Generation asked EPRI to look into the life history and ecology of the American eel in relation to migration on the Susquehanna River as part of the company's efforts to relicense the Conowingo Hydroelectric Generating Station in 2014. The EPRI study included analysis of the ecological consequences—both positive and negative—of providing upstream passage for the eel at Conowingo and three other hydroelectric facilities on the main stem of the Susquehanna River.

Benefits and Detriments

The study was the first of its kind to examine the American eel in the context of the Susquehanna River drainage basin and ecosystem. Investigation of the entire length of the river was important because Conowingo is only the lowest of four hydro facilities separating upstream freshwater habitat from the eels' return destination in the Chesapeake Bay and ultimately the Sargasso Sea, where they spawn.

The study's results indicate that there are some potential ecological benefits to providing upstream passage. Enhanced access to upstream habitats would increase the abundance of female eels upstream, as well as the number of eggs each female produces. There is some limited evidence that eels have positive benefits for the life cycle of a freshwater mussel species that were common prior to damming of the river.



Nevertheless, it is not clear that providing passage to the upstream freshwater habitat would facilitate near-term rebuilding of the American eel stock, owing to detrimental consequences likely to offset the benefits:

- Increased downstream passage mortality as a larger number of eels pass through four hydroelectric projects, an outcome that cannot be mitigated at this time;
- Enhanced infestation by a parasite, which could reduce eels' swimming ability during downstream migration and inhibit travel to the Sargasso Sea spawning ground;
- Eel deaths caused by introduced predators in the upstream habitat; and
- Exposure to and bioaccumulation of toxic chemicals in freshwater sediments, which could further impair eels' swimming ability and reduce egg viability.

These findings are expected to be widely applicable to other hydroelectric facilities in the eastern United States.

Eel Passage Research Center

In the meantime, EPRI is focusing on the problem of downstream migration through a collaborative, multinational research effort beginning this year on the Canadian-American border along the St. Lawrence River. The new Eel Passage Research Center, slated to begin field studies in 2014, will investigate and develop biologically and operationally effective means of diverting adult eels around the intake structures of large and medium-sized hydro dams.

Building on previous research, the center will evaluate the effectiveness of electricity, light, sound and vibration, electric and magnetic fields, and water velocity gradients in guiding eels to collection points. Methods for monitoring the behavior of migrating eels and for collecting them for transport around hydropower facilities will be investigated, as will the problem of debris loading—a significant issue in the St. Lawrence River and elsewhere.

The center's research will help hydro operators meet future downstream eel passage requirements, avoid shutdowns and other costly operational responses, and avoid large structural changes, such as installing full intake screening. The benefits of this research will extend from the rivers of eastern North America to Europe, Scandinavia, and the British Isles, where the European eel is listed as critically endangered by the European Union and Norway.

For more information, contact Paul Jacobson, pjacobson@epri.com, 410.489.3675.

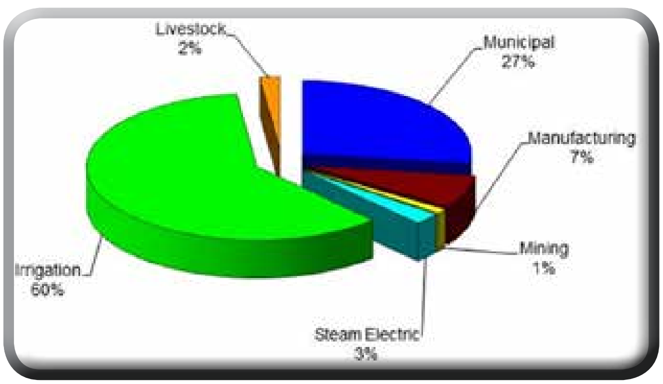
TECHNOLOGY AT WORK

Member applications of EPRI science and technology

Texas Study Clarifies Electricity Sector Water Use

As Texas continues to experience severe drought, concerns have arisen among state legislators and other stakeholders about the water consumption of various sectors in the state, including electric power generation. Thermoelectric power plants account for approximately 40% of total U.S. freshwater withdrawals, with most of that water used for cooling. Some stakeholders have suggested that retrofitting thermoelectric plants with closed-cycle or dry cooling technology would significantly reduce the water required to generate electricity.

With the Texas legislature evaluating water use throughout the state, four of the state's electricity providers—American Electric Power (AEP), the Lower Colorado River Authority (LCRA), Luminant, and NRG—asked EPRI to conduct an analysis of water use by the various sectors in Texas to help clarify the energy/water nexus. The goals of the study were to compare the water consumption of the electric power industry with that of other sectors and to analyze the viability and impacts of implementing various power plant water-conserving cooling technologies.



Electric power generation accounts for only 3% of water consumption in Texas.

Withdrawal Versus Consumption

One of the most important considerations when analyzing water use is the difference between water withdrawal and water consumption. Withdrawal refers to the volume of water removed from a water body and then returned to the environment; water consumption refers to water that is withdrawn but then becomes unavailable for other uses. Although thermoelectric power plants account for a large portion of total U.S. freshwater withdrawals, most of that water is used for cooling and then returned to the originating water body without substantially affecting overall availability.

Using 2009 data, EPRI's analysis of Texas water consumption by sector showed that steam electric plants account for only 3% of the total water consumed, with irrigation accounting for 60% and municipal use for 27%. The study also made comparisons with typical American household water and electricity consumption, which averages 300 gallons of water daily and 20 kilowatt-hours of electricity. The typical Texas power plant with once-through cooling consumes 9.5 gallons of water to produce that amount of electricity; thus, the amount of water needed to supply a household's daily electricity needs compares with only about 3% of its normal water use for showers, laundry, dishwashing, lawn irrigation, and other day-to-day activities.

The study provided information on usage trends as well, pointing out that U.S. electric power producers have maintained steady water withdrawal rates over the last 50 years, while the population of the U.S. has increased by nearly 60%. The trend for water consumption per unit of energy has also steadily decreased over the same period as companies have made use of new and more efficient cooling technologies and water-conserving generation options.

Reports to Stakeholders

EPRI shared the results of its analysis in a hearing with the Natural Resources Committee of the Texas House of Representatives and arranged follow-up meetings with legislators, the media, and other stakeholders. "The overriding concern has been whether electric power production is consuming a disproportionate share of the state's water during a period of drought," noted Gary Gibbs, manager of government and environment affairs at AEP. "The study has been very effective in explaining how much water is really consumed in producing electricity in a logical way that policymakers can understand."

During the hearing, EPRI also made the point that replacing existing power plants to achieve additional water conservation comes with significant cost and could potentially impact electricity rates. "One of the key results of the study was an increased understanding that water issues in Texas can't be solved simply by changing how electricity is produced," said Scott Ahlstrom, manager of engineering services at LCRA.

According to Ted Long, manager of water resources at NRG, the study has been quite valuable in improving a variety of stakeholders' understanding of water issues: "I've used the study several times to answer questions about how our water use compares with municipal or agricultural use."

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New Guidance for Enhanced Nuclear Safety

Severe accidents at nuclear power plants are rare. But the consequences of the few that have occurred have extended the focus beyond how to avoid accidents—the main concern before Three Mile Island—to how to respond and mitigate damage if a serious accident does develop. Essentially this means including not only procedures to avoid significant damage to the nuclear fuel but also scenarios and management contingencies where the fuel may have begun to melt.

EPRI compiled key information and guidance on this front in 1992 with the publication of *Severe Accident Management Guidance Technical Basis Report* (TR-101869), a document that has stood the test of time and continues to be relevant. In October 2012, EPRI published an updated technical basis report (1025295) to address the lessons learned from the 2011 Fukushima accident and incorporate other insights from research and analysis conducted over the 20 years since the original technical basis was produced.

Planning for Mitigation

While the actions described in the original guidance report continue to represent appropriate responses to severe accident conditions, a detailed examination of the Fukushima accident has highlighted a number of areas that need to be addressed for future planning and management:

- Unconventional cooling water. All available sources of water should be considered for emergency cooling, regardless of quality, so that proper and timely decisions can be made when managing an accident. The updated technical basis report addresses the value of injecting seawater or water from other raw-water sources to reestablish cooling of a damaged core or of core debris.
- Spent fuel pool. The updated report addresses actions to cool overheated fuel stored in the spent fuel pool, which could cause a severe accident even if the operating core and primary containment are secure.

- Natural disasters. Plans should consider the particular challenges posed by an external event (such as an earthquake or large flood) that can constitute a common cause of failure of plant systems, especially when the event can affect multiple units at a site.
- Hydrogen formation and ignition. New or different measures may need to be taken to manage hydrogen that could be generated by the reaction of water with overheated fuel.

Limiting Radioactive Release

A second recent report (1026539) discusses measures that might be taken to limit the release of radioactive species over an extended period following an accident. These analyses have been completed for boiling water reactors that use Mark I or Mark II containment designs; further research is under way for other reactor and containment designs.

If the integrity of the containment building is lost, releases could result in the radioactive contamination of land in the vicinity of the plant. The EPRI analysis explored strategies that could maintain or enhance the containment function, including the installation of dedicated venting systems equipped with extensive filters. Such systems would provide a means to allow controlled releases of the materials in the containment atmosphere and prevent pressure buildup inside containment.

The report found that no single strategy is optimal for retaining radioactive fission products in the containment system. The most effective strategies involve combinations of active strategies to cool damaged fuel and venting of the containment. Even sophisticated filtered venting systems alone are ineffective if the damaged fuel cannot be cooled, because if the fuel remains molten, it can melt through the containment boundary or cause other failures.

Strategies in existing severe-accident management guidelines provide substantial benefit in reducing radiological releases. These strategies address cooling the damaged core materials by injecting water or by spraying water into the containment atmosphere. Either of these strategies can help prevent the molten core materials from causing further damage, can help remove heat from the containment atmosphere, and can capture radioactive species that might otherwise be released from containment.

For more information, contact Stuart Lewis, slewis@epri.com, 865.218.8054, or Rick Wachowiak, rwachowiak@epri.com, 704.595.2774.

REPORTS & 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.

Catalyst Management Handbook for Coal-Fired Selective Catalytic Reduction NOx Control (1023923)

This report provides guidance for operators of selective catalytic reduction (SCR) systems, helping them to identify a schedule and approach for catalyst replacement or supplementation that will minimize the impact of NOx-control process equipment on the cost of power production. The report is based on three reference cases, distinguished by coal type: two eastern bituminous coals with different arsenic levels and one Powder River Basin coal.

Current Strategies for MATS Compliance (1023938)

To comply with the EPA Mercury and Air Toxics Standards (MATS), issued in 2012, power plants need to reduce the stack emissions of mercury, filterable particulate matter, and acid gases. To help utilities maximize performance and overall cost-effectiveness, this report highlights compliance strategies that control all three major MATS pollutants holistically. It focuses on currently available technologies but also discusses novel technologies, such as the sorbent activation process and sorbent polymer composites, which show promise for substantially reducing compliance costs.

Monetizing the Geospatial Information System (GIS): The Value of GIS Data Quality for Electric Utilities (1024303)

The intelligence of the smart grid relies critically on geospatial data to represent and track the locations of numerous devices within the connectivity model of the distribution system. A geospatial information system (GIS) fills this role. This project used surveys and financial modeling to quantify the costs and benefits that can be expected from improvements in GIS data. The financial model is based on standard metrics and the probabilities of achieving the desired impact.

Space Weather 101 (1025860)

This report describes the basic physical concepts associated with space weather, especially the effects of solar storms on high-voltage power transmission systems. Space weather is an extremely complex and multifaceted phenomenon. Focusing on power grid–related effects, the report addresses coronal mass ejections, which are known to be the most important driver of large geomagnetically induced currents, and describes ongoing research being conducted to better understand, predict, and mitigate the effects of such disturbances on power systems.

Spent Fuel Pool Accident Characteristics (3002000499)

This report provides an up-to-date assessment of analytical tools for evaluating risks related to spent fuel pools (SFPs) in the case of a major accident and provides a compendium of information on SFP configurations that will facilitate utilities' safety analyses. The report summarizes typical SFP characteristics and discusses the challenges that may lead to fuel uncovering or damage. The use of a probabilistic risk assessment approach to characterize the SFP risk profile is also presented.

Plant Manager's Guide for BWR Source Term Control and Reduction (3002000820)

This guide, the result of a collaborative effort between the Institute of Nuclear Power Operations (INPO) and EPRI, provides boiling water reactor (BWR) plant managers with simplified, how-to guidance on radiation field source term reduction. The goal is to reduce radiation fields and, ultimately, to aid in improving collective radiation exposure. The content was collected from both plant experience and technical studies.

Evaluation of Smart Phone Apps Used to Measure AC Magnetic Fields (3002001136)

A number of smart phone apps are currently available for measuring magnetic fields. This project investigated the characteristics of the sensors used for measurement as well as the integrated circuit in which the sensors are embedded, and it experimentally evaluated several representative applications for two popular smart phone platforms. Comparisons with laboratory-grade measurements suggest conclusions about how app-based readings can be properly (and improperly) interpreted.

Evaluation of Alternative Spill Containment Systems (3002001291)

Conventional systems for containment of mineral oil spills at substations rely on concrete basins or vaults and earthen berms that are unlined or lined with clay or synthetic membrane liners. This report, developed from a literature review, interviews with utility personnel, and responses to a questionnaire on spill containment practices, describes the capabilities of alternative equipment, materials, and structures to prevent the release of mineral oil to the environment.

WIRED IN

Perspectives on electricity

Philip B. Jones, *Commissioner, Washington Utilities and Transportation Commission*

David Boyd, *Commissioner, Minnesota Public Utilities Commission*

New Approaches for Building Out a Smarter, More Resilient Grid

Make no mistake: the grid is changing. We may be on the cusp of a significant transformation of how we use and consume power. And as regulators, we are preparing.

Getting there won't be easy. Integrating new and diverse resources will come at the expense of traditional generation, forcing older plants to be operated differently or, possibly, taken off line entirely. And we are doing this at a time when we are facing capital expenditures of about $2 trillion in both generation and the grid over the next 20 years. Yet somewhat paradoxically, utilities must cope with sluggish load growth and increasing amounts of customer-owned generation on a distributed basis.

As regulators, we find ourselves in a tough bind. How do we ensure reliable and affordable electricity today while also ushering in a new system that is based as much on flexibility as it is on reliability?

In Washington State and the Western Interconnection, we are facing three related challenges with the grid. First, we are integrating large amounts of intermittent generation, such as wind and solar, as required by renewable portfolio standards—ranging from 15% to 33% of load. This mode of operation requires new approaches and places new stresses on existing generation resources as they ramp up and down more often in order to balance load and generation in real time.

Second, we are preparing for the consequences of increasing weather variability and the likelihood of natural and man-made disasters that impact the grid, such as forest fires, tsunamis, earthquakes, or cyber intrusions. Preparation for such disasters involves more than just traditional outage management readiness, encompassing the broader challenge of building more resiliency into the grid.

Finally, technology innovation is changing the paradigm for integrating more intelligence into the grid in the form of phasor measurement units, synchrophasors, and smart devices based on Internet Protocol. The Western Interconnection synchrophasor project will allow us to measure precisely, in real time, power flows across the 14-state grid region, which will assist us in better utilizing transmission assets and pinpointing outages when they occur. We will need to invest continually in R&D to develop new approaches in both hardware and software as we manage this transition to a grid with more transactive energy.

Given this country's diversity, states in other regions are dealing with different challenges. In Minnesota, the state's renewable portfolio standard prompted significant development of new renewable energy. The Minnesota commission has integrated these investments to meet the standard, along with energy efficiency standards, in a way that maximizes long-term benefits.

While development of renewables is critical to meeting public policy goals, it is coming at a time when Minnesota faces a supply glut from its traditional fossil fuel resources. And the effort is somewhat at odds with the regulators' mission of providing reliable electricity at the lowest cost because at the moment, renewable energy tends to be more costly. But as new federal limits on greenhouse gas emissions impact fossil fuels, the relative cost-effectiveness of renewable energy is increasing.

The dilemma is that public policy goals change over time. This means we need a grid that can handle sudden increases in renewable development and traditional forms of electricity at the same time. We can utilize numerous regulatory mechanisms to deal with these challenges. Some tools, such as reviewing utility business models to make sure useful new approaches are not being overlooked, are old hat. But other approaches, such as exploring the potential that new technologies (the smart grid, modular nuclear, dispersed generation, solar, and mini-grids) offer for the production and delivery of electricity services, may be necessary as well.

Utility regulation has served this country well for more than 100 years; we've ushered in numerous changes in how we use and consume electricity since the early 1900s. Over the next century, we will remain on the cutting edge. As utilities focus more on selling services than on marketing electricity as a commodity, regulation needs to adapt and accommodate such changes in utility business models.

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JOURNAL

ELECTRIC POWER RESEARCH INSTITUTE

SUMMER 2013

Printed on recycled paper in the United States of America

3002001742