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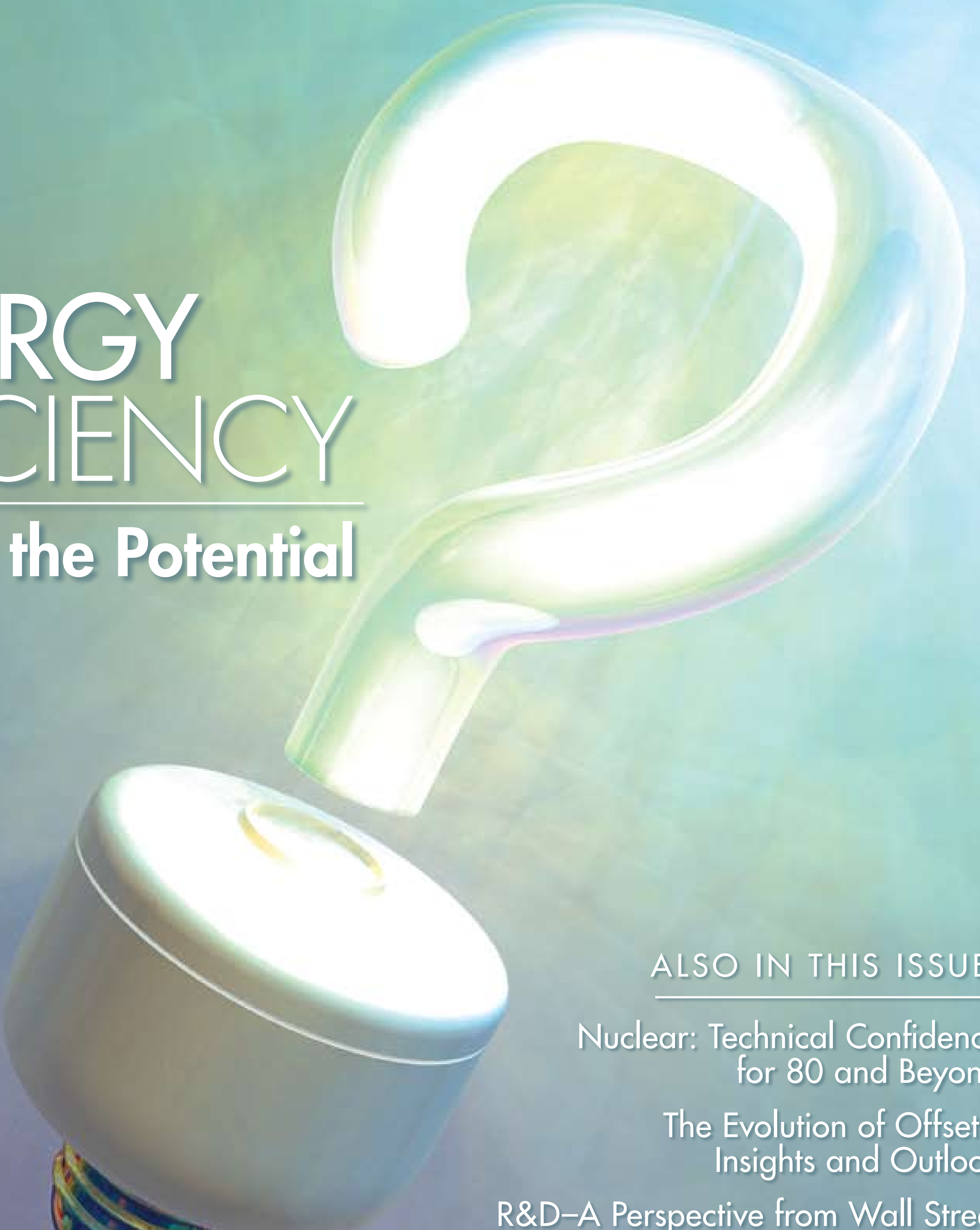
EPRI JOURNAL

ELECTRIC POWER RESEARCH INSTITUTE



ENERGY EFFICIENCY

What's the Potential

ALSO IN THIS ISSUE:

ELECTRIC POWER RESEARCH INSTITUTE

The Electric Power Research Institute, Inc. (EPRI) conducts research and development for the global electricity sector. An independent, nonprofit organization, EPRI brings together experts from academia and industry as well as its own scientists and engineers to help address challenges in electricity generation, delivery, and use, including health, safety, and the environment. EPRI also provides technology, policy, and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90% of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

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Contact Information
Editor-in-Chief
EPRI Journal
PO Box 10412
Palo Alto, CA 94303-0813

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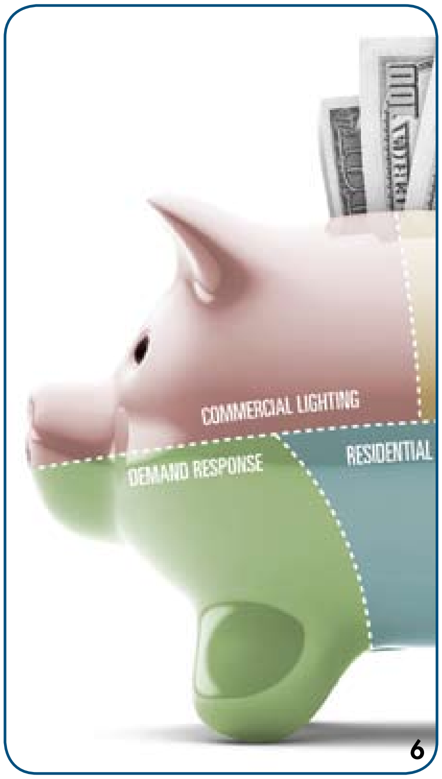

VIEWPOINT

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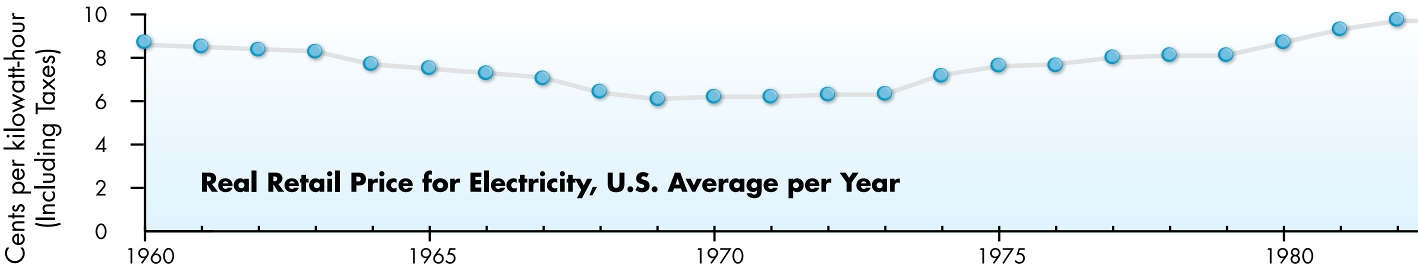
DEPARTMENTS

VIEWPOINT

by Steve Specker, President and CEO, EPRI

The Challenge of Sustaining the Law of Constant Real Electricity Prices



In the United States, we are in the midst of climate and energy policy debates whose outcome will shape the future of our electricity infrastructure for decades to come. There is broad agreement that we must make the transition to a low-carbon electricity infrastructure. We see less agreement and understanding regarding the critical importance of the cost of electricity provided to consumers by such a low-carbon infrastructure.

As a result of advancements in technology and operating efficiencies, the real price of electricity in the United States today is about the same as it was 50 years ago. And we have achieved this while substantially reducing environmental impacts. This tremendous accomplishment by all stakeholders in the electricity sector has been a key driver of economic growth and has provided great public benefit.

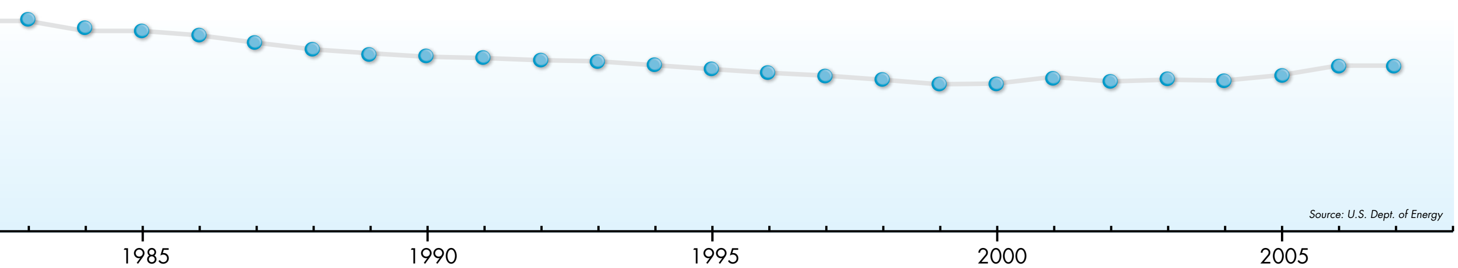
Some now argue that we must break with this 50-year trend in order to create a low-carbon future, and that we must accept substantial, long-term increases in the real price of electricity. I disagree. If we are unable to rapidly deploy cost-effective low-carbon technologies, this may indeed cause real electricity prices to rise in the short term. But to simply accept that real electricity prices will rise over the longer term means tying the nation to a continuing stream of consumer subsidies to ease the pain of high prices, rather than inspiring the technology innovation that will meet our carbon goals *and* spur economic growth.

We need a new paradigm—one that drives innovation in, and accelerates the deployment of, cost-effective low-carbon electricity technologies.

In 1965 Gordon Moore of Intel observed that, over the long term, the number of transistors that could be placed inexpensively on an integrated circuit doubled every two years. Over the years, Moore's law has become a self-fulfilling prophecy that continues to drive relentless innovation. I believe that we have experienced an equivalent to Moore's law in the U.S. electricity sector. Based on at least 50 years of observation, this law simply states that *the real price of electricity stays constant over time.*

Sustaining this "law of constant real electricity prices" should be the driving force for relentless innovation across the entire portfolio of low-carbon electricity technologies. It must also be the yardstick by which alternative low-carbon technologies are compared. As each low-carbon technology moves from idea through research, development, demonstration, early deployment, and wide-scale deployment, it must be continually subjected to rigorous, objective engineering economic analysis to assess its cost of electricity against the law of constant real electricity prices.

Some will say this is unrealistic—that higher electricity prices must occur in order to force the desired changes in consumer behavior and technology adoption. Again, I disagree. We know



that there are numerous energy efficiency technologies that can generate zero-carbon "negawatts" at costs below real electricity prices. We also know that France essentially decarbonized its electricity infrastructure through the systematic construction of standardized nuclear plants while achieving globally competitive real electricity prices. We see South Korea doing the same with its nuclear program at present. These technologies exist today. Just imagine where continuing innovation and experience can take us.

There is no single path to a low-carbon electricity infrastructure. Technologies and policies to help make the most efficient use of electricity will likely be common to all infrastructures. However, the mix of technologies used to produce the vast quantities of needed low-carbon electricity will vary widely, depending on availability of resources and prevailing public policies. But in charting a low-carbon future, all stakeholders should accept the challenge presented by the law of constant real electricity prices so that, like Moore's law, it can become a self-fulfilling prophecy.

Studies by EPRI and others consistently conclude that societies will increasingly electrify as long-term targets for atmospheric greenhouse gas concentrations are reduced. As a result, modern societies will require ever-increasing quantities of low-carbon electricity to fuel economic growth. Electricity will be the critical "raw material" for industry and transportation. Those states, regions, and countries that build a reliable, low-carbon electricity infrastructure that provides users with electricity at globally competitive prices will have an engine for economic growth. Their consumers will also spend less for energy, leaving more income for savings, investment, and education—key elements in sustaining global leadership and prosperity. And I have little doubt that, globally, the competitive real price of electricity will be constant over time.

At EPRI we accept and relish the challenge of sustaining the law of constant real electricity prices while helping shape a low-carbon future. Our job is to improve the reliability, cost, and environmental performance of a full portfolio of low-carbon technologies. We will not pick winners and losers—we will try to make all of them winners. Ultimately the law of constant real electricity prices will determine not only the winning and losing low-carbon technologies, but also the winning and losing economies in a low-carbon world.

SR Specker

Steve Specker
President and Chief Executive Officer

SHAPING THE FUTURE

Innovative approaches to upcoming challenges

The Paradox and the Promise of Nanotechnology

Electricity companies are accustomed to the paradox of using very large infrastructure to move very small electrons. Nanotechnologies have the potential to take this paradox to the next level as some of electricity's biggest challenges are addressed with the world's smallest technologies. Nanotechnology manipulates matter at a minute scale. (A nanometer, for example, is one billionth of a meter.)

Nuclear power exemplifies big results (megawatts of electricity) from small (nuclear) processes. In the nuclear arena, two areas of research point to the potential for megascale progress through nanoscale solutions.

Nanocatalysts From Sonoluminescence

EPRI research indicates that nanocatalysts may hold the key for the large-scale production of hydrogen at low temperatures. Currently large-scale hydrogen production is hampered by processes that require temperatures up to 900 degrees centigrade. This limitation could be important in the development of very-high-temperature gas-cooled reactor designs, which will require the capability to produce large amounts of hydrogen.

Supported nickel catalysts with a core/shell structure in a nanoparticle form have met the requirements to produce significant quantities of hydrogen efficiently and at low temperatures. Generating these nanocatalysts may be possible through a process driven by sonoluminescence—the emission of light associated with the "catastrophic collapse" of microbubbles oscillating under ultrasound. Temperatures and pressures achieved by the collapse of micron-size bubbles range up to 50,000 degrees Kelvin and 10,000 atmospheres. Research indicates that multi-bubble sonoluminescence can be used to make nanocatalysts with important new properties.

It's yet another nanoparadox in that the extraordinarily high temperatures and pressures achieved at nanoscale enable a process that can proceed very rapidly at an overall lower temperature, without any toxic products.

For more information, contact Ken Barry, kbarry@epri.com, 704.595.2040.

MagMolecules and Liquid Nuclear Wastes

Processing low-level waste effluent streams from nuclear plants has remained a persistent challenge because dissolved radioactive contaminants may be present in only minute quantities, making their removal from large volumes of liquid difficult and expensive. Even if the liquids are evaporated to reduce the volume, radionuclides may represent only a small fraction of the total material that must then be disposed of. Ion exchange systems can remove contaminants more selectively but still produce an unnecessarily large volume of solid waste.

A new approach now being refined in a pilot project promises to greatly reduce radioactive waste volume by using magnetic molecules that target specific radionuclides dissolved in a low-level waste stream. EPRI has received one patent and filed a second application for the MagMolecule Process, which it expects may also be used in other important applications, such as removing heavy metals from industrial effluents and groundwater.

One noteworthy aspect of the process is that it begins with proteins that are produced in the human body. Called ferritins, they are used by the body to store iron in the spleen and liver. The computer industry has used synthetically produced and magnetically stronger "magneto-ferritins" to manufacture data storage disks. EPRI's research has focused on modifying magneto-ferritins to bind selectively to specific contaminants—initially strontium and cesium—that represent important radioactive constituents of low-level waste.

The nano-engineered proteins bind to the targeted contaminants, and with their magnetic core can then be magnetically filtered from the effluent stream. The magnetic filter can be backwashed to collect the solid by-products and then be reused.

Laboratory results indicate that MagMolecule technology has the potential to reduce waste volume by a factor of up to 5,000, compared with conventional ion exchange treatment. Researchers have successfully targeted strontium and cesium with the magneto-ferritins. If the process can be further refined to target other elements and applied at a commercial scale, the result could be significant cost savings for low level waste management in nuclear power plants. Significant potential exists as well for applications in other industries.

Since the laboratory phase of this research was completed in 2007, ongoing research and development has focused on determining what is needed to scale up the process, testing more robust base molecules, and identifying other steps that can lead to commercialization.

Among the results that researchers would like to achieve:

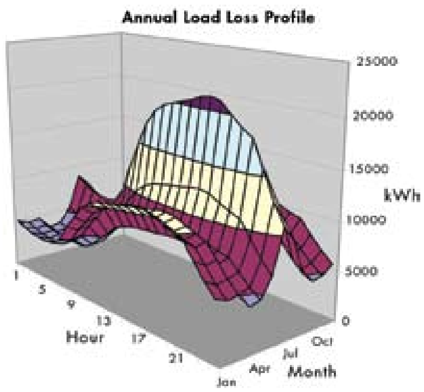
- a selective molecule capable of the complete removal of a target contaminant and no other;
- complete transfer of the absorbed contaminant and magnetic molecule onto the magnetic filter; and
- a robust process, capable of performing in realistic plant conditions with varying pH, temperature, and conductivity.

In practice, the system's effectiveness will be determined by the design and quality of the magnetic molecules and the process application equipment, such as filters. Pilot test work is being carried out at Clemson University.

For more information, contact Sean Bushart, sbushart@epri.com, 650.855.2978.

OpenDSS Will Stimulate Smart Grid Development

EPRI's Distribution System Simulator (DSS) has long provided powerful modeling capabilities as a proprietary tool for analyzing utility distribution systems. Now, in an effort to stimulate rapid development of new modeling applications for use in the smart grid, EPRI is releasing the software as an open-source program called OpenDSS. This release will make the software available to researchers, software vendors, utility engineers, and others to support analysis of both system planning and real-time operations in more technologically complex distribution systems.



A smart grid overlays the electricity network with communications and computer control, enabling significant gains in system reliability, capacity, efficiency, and demand response. It also facilitates the delivery of more customer services, including real-time pricing, and the addition of more distributed generation, including intermittent renewable resources. Individual technologies related to smart grids have been available for some time, and demonstrations of the smart grid concept are targeted to receive hundreds of millions of dollars from the federal economic stimulus, but effective integration of the various communications and control elements will require new distribution system analyses. OpenDSS provides for the analyses and structure to incorporate these elements into a system safely and effectively.

Jump-Starting Applications

Making OpenDSS available to system modelers should spur development of new analytical applications, including improvements in fault location, transformer load management, voltage control, energy loss reduction, and integration of distributed resources. As new application modules are incorporated into the program, OpenDSS will gain enhanced capabilities to create load profiles, perform annual system simulations, and handle complex power flow calculations in real time. System operators will be able to use the real-time simulations to reconfigure distribution circuits to optimize performance, while utility planners will use annual load and generation models to forecast future system needs.

"We're seeing the emergence of a new paradigm in managing distribution systems," said Mark McGranaghan, senior technical manager in EPRI's Customer Systems group. "OpenDSS will play a major role in this transformation by modeling the foundations of the smart grid. It can take information from distribution system sensors and a utility's geographic information system, and use this information to provide continually updated models of system conditions that enable operators to optimize performance and reduce losses. Also, it can provide the long-term load and generation forecasts needed for critical decisions about system investment, including effective ways to prepare for adding renewable energy resources. By providing individual utilities, university researchers, and distribution management system vendors an open platform for creating new modeling applications, we can move significantly faster in developing the analytical capabilities needed to create smart grids."

Working With the Software

Because OpenDSS can be used either as a stand-alone program or as a component of an existing utility software platform, users will have flexibility in customizing distribution system analyses to fit their requirements. The program can also be expanded and modified to meet future company needs. It has been designed to operate in the Microsoft Windows environment and supports nearly all steady-state analyses commonly performed on utility distribution systems.

OpenDSS has several built-in solution modes, including power flow as a real-time snapshot of a distribution system, cumulative daily and yearly power flows, harmonics, dynamics, and fault studies. Experienced software developers can further customize OpenDSS by downloading the source code and modifying it as needed, writing software that controls the OpenDSS through the component interface, or developing dynamically linked libraries (DLLs) that plug into the program. OpenDSS is available from the SourceForge.net website.

For more information, contact Roger Dugan, rdugan@epri.com, 865.218.8074.

ENERGY EFFICIENCY:

What's the Potential?

THE STORY IN BRIEF

A new EPRI study finds that utility energy efficiency and demand response programs can significantly reduce electricity consumption and peak demand in the United States over the next two decades. In particular, the study shows that the annual growth rates for electricity use and peak demand can realistically be reduced by 22% and 46%, respectively, compared with previous federal government projections. Reduction potentials vary greatly, however, among various end-use technologies and in different regions of the country.

Many states are considering policies that would mandate specific improvements in energy efficiency and create regulatory mechanisms allowing utilities to make energy efficiency a sustainable business.

Among other benefits, energy efficiency could have the greatest near-term potential for reducing greenhouse gas emissions from the electric power sector, and utility energy efficiency and demand response programs may provide cost-effective alternatives to building new generating capacity. A fundamental challenge at this stage is to substantiate the potential for energy efficiency and demand-side programs to improve efficiency and deliver the benefits.

EPRI has conducted a detailed study of potential savings from these programs, and the results have been published in a recent report, *Assessment of Achievable Potential From Energy Efficiency and Demand Response Programs in the U.S. (2010–2030)*. The new EPRI study provides utilities and other industry stakeholders with a detailed breakdown of which technologies, economic sectors, and geographic regions offer the greatest potential for efficiency enhancements and what targets are achievable.

"Utilities can use our results to help inform decisions for their programs aimed at reducing the growth of energy consumption and peak demand," said Omar Siddiqui, program manager for EPRI's Energy Efficiency program. "The regional results can also provide useful calibration points to compare with those from state-level and utility studies and to use in identifying promising opportunities for improvement."

A Detailed, Bottom-up Approach

Most national studies of energy efficiency potential have been based on estimates of savings that could result from a few key drivers, such as introduction of new policies, expected changes in building codes and efficiency standards, and assumptions about advanced technologies. By contrast, EPRI's study takes a bottom-up approach based on currently available technologies and standards, together with information about actual utility experiences with energy efficiency and demand response programs. The advantage of this approach is that it isolates the impact of utility programs and enables detailed segmentation of savings potential by region, sector, and specific end-use application.

The study screened more than 300 efficiency-improving technologies for cost-effectiveness to confirm that the present value of expected consumer savings would exceed the extra cost of the equipment purchased. This economic screening projected that if consumers adopted all of the most efficient and cost-effective technologies now commercially available, there would be an 11% decline in electricity consumption by 2030, compared with what would otherwise be expected.

Not all consumers, however, are willing to buy the most energy-efficient alternatives. For example, some consumers have resisted purchasing highly efficient compact fluorescent lamps because of a dislike of the color spectrum the lamps emit. Supplies of some energy-efficient products may be constrained as manufacturing scales and distribution channels emerge. Taking such market resistance into account, the resulting "maximum achievable potential" for reducing electricity consumption in 2030 is calculated to be 8%. This maximum achievable figure assumes a scenario of perfect customer awareness of utility- or agency-administered programs and effective, fully funded program execution. The maximum achievable number includes the effect of customer rejection of efficiency technologies.

A "realistic achievable potential" was calculated for efficiency improvements by examining real-world experience with such programs. The finding: a 5% decline in electricity consumption by 2030—representing total savings in that year of 236 billion kilowatt-hours (kWh). For perspective, that's equivalent to the electricity consumed today in Illinois, Oklahoma, and Kansas combined. In terms of the annual growth rate for electricity, the realistic achievable potential represents a reduction of 22% from the U.S. Energy Information Administration's (EIA's) 2008 Annual Energy Outlook reference case.

The Most Promising Opportunities

The EPRI analysis identified two priority areas for utility programs to target. The first area includes familiar end uses—such as commercial lighting, industrial motors, and residential cooling—that already have a long history of efficiency improvements. Sometimes referred to as “low-hanging fruit surrounded by barbed wire,” these applications have well-proven, highly efficient technologies available, but the widespread adoption of these technologies has been hampered by various circumstances.

In the case of commercial lighting, part of the problem is simple inertia. Most office buildings and stores have long turnover periods for lighting systems that perform adequately. The challenge for industrial motors, on the other hand, is to increase market penetration of energy-saving adjustable speed drives in the 1- to 5-horsepower segment. Improving residential cooling will require overcoming both consumer inertia and higher initial prices for the more efficient equipment.

The second priority area would target equipment introduced more recently, such as computers and consumer electronic devices, which are adding substantially to the growth of electricity consumption.

Findings in both areas can help utilities design their energy efficiency programs to overcome existing barriers and encourage consumers to adopt the most efficient technologies available.

Study results indicate that the realistic achievable potential for energy savings in just these two areas is startling. By 2030, annual electricity savings for commercial lighting alone could be as great as 90 terawatt-hours (TWh), while industrial machine drives could save 50 TWh and residential electronics more than 40 TWh.

Regional Disparities

The study also reveals differences in energy efficiency savings potential among major U.S. census regions. In absolute terms, the greatest potential for efficiency savings lies in the South, which has the nation’s highest electricity consumption. It is estimated that by 2030, the realistic achievable potential annual savings for the South will be about 190 TWh.

In relative terms, the West has the most rapid forecast rate of consumption increase—1.6% per year through 2030, compared with 1.4% for the South—and thus the largest potential for efficiency improvement measured as a percentage decline in expected growth. The realistic achievable annual savings potential for the West is estimated to be about 80 TWh in 2030.

In absolute terms, the Midwest is the second largest region in both current and forecast consumption, but its annual growth rate is the smallest of the four regions—about 0.7%. The region’s realistic achievable savings potential is about 75 TWh per year by 2030.

Electricity consumption is currently lowest in the Northeast, which has an expected growth rate of 0.9%. The Northeast also has the smallest energy efficiency savings potential among the census regions.

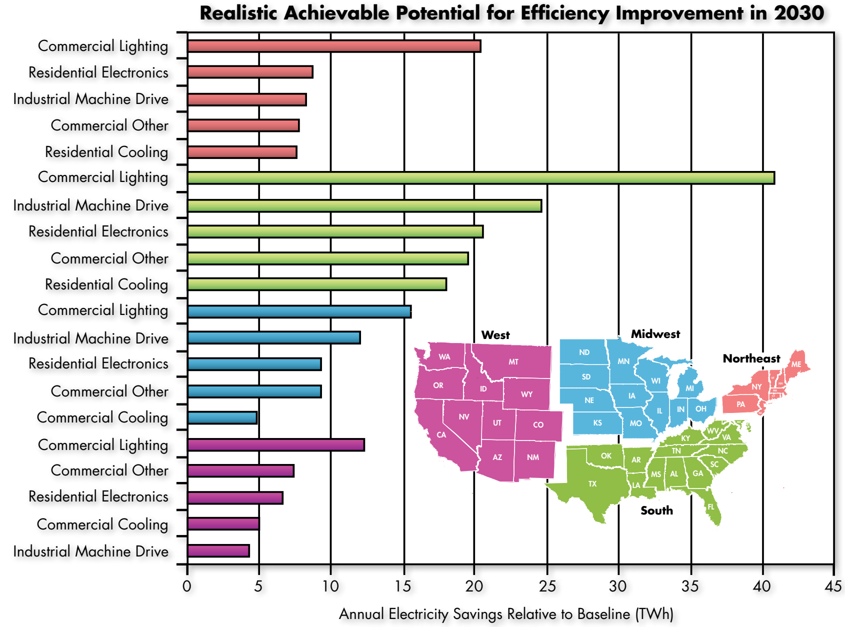
Generally speaking, the Northeast and West have a longer legacy of energy efficiency programs than the South and Midwest. Between 1995 and 2006, more than half of the 74 TWh cumulative savings achieved by such programs came from the West, primarily from California. Lacking a long history of these programs, the South and Midwest show greater disparity between the realistic achievable potential savings projected for the future and those actually achieved in recent years. As shown in the graph below, however, the most promising end-use opportunities for efficiency improvements are remarkably similar across all regions.

“Prior experience with efficiency programs will make a big difference in achieving future goals—there’s a steep learning curve,” said Siddiqui. “It will therefore be important for utilities that have not emphasized such programs in the past to adopt what have become established as industry best practices and to make significant investments in new program infrastructure and customer education.”

Reducing Peak Demand

The study assessed the potential for reducing peak demand through utility programs that promote energy efficiency generally and that target demand response specifically. Together, the assessment concluded, such programs have the realistic achievable potential to reduce peak demand by about 157 gigawatts (GW), or 14%, in 2030. In terms of the annual growth rate for peak demand, the realistic achievable potential represents a reduction of 46% from the

Realistic Achievable Potential for Efficiency Improvement in 2030



EIA's 2008 Annual Energy Outlook reference case.

About half of this reduction would result from utility demand response programs, which could be expected to achieve roughly equal savings across the residential, commercial, and industrial sectors. Promising opportunities for residential demand reduction include price response measures and direct load control of central air conditioning and water heating systems. In the commercial sector, interruptible loads represent by far the largest potential reduction, followed by price response. Interruptible loads and price response are also important for the industrial sector, followed by direct load control of manufacturing processes.

In each case the demand reduction measures can be facilitated by two-way communication between a utility and its customers. Such communication can provide switching signals for load control applications or dynamic prices that customers can use to optimize the time of day they operate end-use devices. Introduction of so-called smart grid technologies can also help foster demand response.

Implications

A major conclusion of the study is that substantial improvements in energy efficiency and reductions in peak demand are realistically achievable through utility programs. The report cautions, however, that significant investment in these programs beyond current levels will be required. Specifically, the cost of attaining the maximum achievable potential could range from $25 billion to $63 billion in 2030.

Since the study was designed to provide an independent, analytically rigorous estimate of the electricity savings potential of energy efficiency and demand response programs, utilities are expected to be able to apply specific results to improve the effectiveness of these programs. An additional implication is better allocation of resources, because utilities can focus on the most promising opportunities. Moreover, the study provides information to apply in measuring the success of existing programs, as well as new data to use in discussions with policymakers about what is realistically achievable.

Additional EPRI research is now focusing on more-detailed scenario analyses for the future, especially with respect to the potential impact of electricity prices, carbon policy, and regulatory incentives on energy efficiency and demand response.

This article was written by John Douglas, science and technology writer. Background information was provided by Omar Siddiqui (osiddiqui@epri.com).

ASK THE EXPERT

An interview with Omar Siddiqui, program manager for EPRI's Energy Efficiency program.

Q. WHY ARE ELECTRIC UTILITIES SHOWING INCREASED INTEREST IN ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS?

A. From a strategic point of view, improving energy efficiency provides the most attractive near-term way to reduce their carbon emissions. From a strictly economic perspective, such programs represent a cost-effective alternative to making capital outlays on new generating resources—particularly to meet peak demand and ease transmission bottlenecks.

Q. HOW DOES THIS STUDY HELP?

A. By taking a bottom-up approach that looks at specific end uses and regional issues, it quantifies the energy efficiency and demand response potential down to the end-use level. This can help utilities identify prime savings opportunities to address through their programs. It also provides important new information on levels of potentially achievable savings, which can be used in discussions with regulators, policymakers, and consumers.

Q. WON'T EXPANDING THESE PROGRAMS BE PRETTY EXPENSIVE?

A. Costs vary widely. Programs that involve residential energy audits and that recommend changes in home lighting, for example, can cost less than 5¢ per kilowatt-hour saved. Measures focused on improving commercial lighting and industrial motors may cost in the range of 5–10¢ per kilowatt-hour. Rebates for residential appliances could run more than 10¢ per kilowatt-hour. The cost-effectiveness of various programs will depend on regional considerations and local electricity rates.

Q. WHAT FACTORS ARE MOST IMPORTANT IN SETTING UP A SUCCESSFUL PROGRAM?

A. Regarding specific in-house expenses related to scaling up efficiency efforts, utilities will need to look very carefully at program design, execution, and evaluation. One key study finding is the importance of the learning curve—experience really improves program effectiveness. In addition, broader infrastructure investments related to smart grids and two-way communications can greatly expedite the introduction of successful new programs.

Q. WHAT BARRIERS WILL NEED TO BE OVERCOME?

A. The most important barriers relate to implementing programs effectively. In particular, both new technology and high-efficiency equipment need to be carefully vetted for applicability. Before implementation, utilities should evaluate the cost-effectiveness of any proposed program. Finally, utilities need to work very closely with their customers to overcome financial barriers and negative attitudes toward certain technologies.

Omar Siddiqui is manager of the Energy Efficiency program in EPRI's Power Delivery and Utilization sector. His work focuses on energy efficiency, demand response, dynamic pricing, and the emerging smart grid infrastructure. Siddiqui joined EPRI in 2007 with more than ten years of experience in the energy efficiency arena, most recently with Global Energy Partners. He received a B.S. in chemical engineering from Stanford University and an M.B.A. from the Anderson School at the University of California at Los Angeles.

Taking the Long View of Nuclear Plants

The increasing demand for energy independence, coupled with the necessity of reducing greenhouse gas emissions, positions nuclear energy to meet current needs and to respond to future needs, such as charging the millions of electric cars expected to fill the streets. But given the many barriers to building and licensing new nuclear plants, existing facilities may be required to run far beyond their initial life expectancies.

"While there is no doubt that the industry aspires to build a new generation of nuclear plants, given the significant regulatory uncertainty, the high cost of new construction, and the status of the credit markets, the first priority must be maintaining existing fleet capacity," said Mano Nazar, chief nuclear officer at Florida Power & Light Company and chair of EPRI's Nuclear Power Council. "Like a classic car from the 1970s, our plants have shown that if they're maintained properly, they become an increasingly valuable asset for the long term. This is not a trend that I expect will change."

Indeed, extending the operating lives of existing plants provides clear advantages. High capacity factors and low operating costs make U.S. nuclear plants some of the most economical power generators in the country. And even when major plant components must be upgraded to extend operating life, these plants represent a cost-effective, carbon-free asset that is critical to the nation's energy future.

In light of this value, power companies have put special emphasis on efforts to preserve and even uprate their nuclear facilities for the long term. "A separate group in our company focuses on renewing the licenses for our plants," said Amir Shahkarami, senior vice president for engineering and technical services at Exelon Nuclear, the largest U.S. operator, with 17 reactors of different vintages. "A good number of our plants are already licensed for 20 additional years, and we'll be licensing the rest of our fleet for extended life to 60 years."

In the United States, nearly all of the 104 operating nuclear power plants are expected to receive license extensions to 60 years; around the world, many other countries are considering life extension to 50 or 60 years as well. Many experts believe, however, that these plants can operate safely well beyond their initial or extended operating periods—possibly to 80 or 100 years. To provide the technical data and rationale supporting continued operation, EPRI has established the Long-Term Operations (LTO) Project. "The objective of this program is to provide technology for the continued operation of the existing fleet," said Shahkarami. "Our company strongly supports this effort."

THE STORY IN BRIEF

Extending the operating lifetimes of nuclear plants to 80 years and beyond will require solid technical justification in a number of areas. Various research entities, universities, power companies, and other stakeholders are collaborating with EPRI in its Long-Term Operations Project, which is conducting the R&D to develop this technical knowledge, with strong emphasis on material degradation issues.

Research Requirements

EPRI's LTO Project supplements existing EPRI, Department of Energy (DOE), and international nuclear research projects and is very specific in its scope and purpose. "We have an objective process based on five key criteria for picking our projects," said John Gaertner, the EPRI technical executive who is leading the effort. "Otherwise, we could end up with science projects that are interesting but don't meet the needs of the industry or the public."

The first criterion is that the project either has to advance high performance within the lifetime that plants are currently allowed to operate or has to remove uncertainties that could jeopardize further life extension. Items to be addressed for the 60-year period, for example, include major components inside the containment vessel that might degrade. When it comes to 80-year research, the focus is on the non-moving infrastructure. "Studies show that most or all vessels will last 60 years, but we haven't looked at them for 80 years," said Gaertner. "We believe they will remain physically sound, but we can't make the technical case today without that research."

The second criterion is that results must be available within a 5- to 10-year time frame; if projects could not be completed within 10 years, the results would show up too late for use in life extension planning. Third, the research must be truly new or be an important extension of existing work. Fourth, the project must provide a solution to a recognized problem, confirm that a potential concern is not in fact a real problem, or improve the capacity factor, reliability, cost, or safety of a plant. Finally, it is desirable, but not required, that activities align collaboratively with DOE's Light Water Reactor (LWR) Sustainability Program, which opens up the opportunity to leverage more expertise and other resources.

Using these criteria, and with guidance from industry advisors, EPRI selected nine projects for funding in 2009 that fall into five categories: managing the aging of passive structures and components, implementing on-line diagnostics to prevent equipment failures, understanding and managing crack growth in primary system materials, enhancing safety analysis tools and methods to meet future needs, and providing a technical basis for silicon carbide fuel cladding.

The materials work is of particular interest to nuclear plant operators, as potential problems are difficult for individual companies to address on their own. "We take very good care of the things that move—the motors, pumps, and relays—and have a program to keep them healthy over the years or modify them to keep them healthy," said Shahkarami. "Our challenge is in passive components such as concrete, metals, and balance-of-plant systems." Because of this need, much of the early LTO research focuses on the long-term reliability of structural elements, especially the aging of concrete and the cracking mechanisms in primary system metals.

Concrete Aging

Concrete structures age and can degrade when exposed to water, chemicals, radiation, and high temperatures. Whether such exposure weakens the concrete to the point that it prevents plant operation beyond 80 years, however, is not well known. "If aging-related degradation is allowed to continue ad infinitum, at some point these structures will be unable to perform their functions," said EPRI project manager Joe Wall.

In a collaborative project with DOE, EPRI is working with the Materials Aging Institute and Oak Ridge National Laboratory (ORNL) to identify critical issues, characterize materials properties, and develop computational materials science on concrete aging. The project will analyze the performance of concrete in LWRs and prioritize the locations where degradation is likely to occur. In the process, it will investigate new nondestructive evaluation and forensic concrete examination methods, prognostic modeling for determining remaining useful life, and potential mitigation measures to help extend life.


Photo: Courtesy of Coastal Abseilers

Extending the operating life of nuclear plants beyond 60 years will require new methods of inspecting and testing concrete.

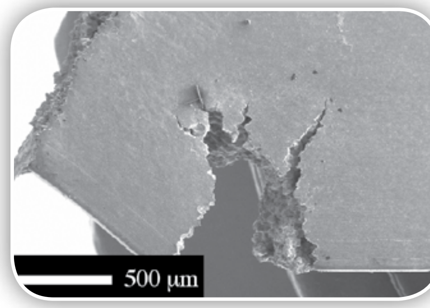
"The project is developing a toolbox that utilities can use to characterize degradation, estimate life span, and mitigate and/or repair concrete structures," said Wall. "We also hope to learn which issues related to concrete aging will be critical for long-term operation of nuclear plants. This will enable us to design future R&D projects to address these issues and build systems for aging management that are truly dynamic, adjusting to new data and new technical insights."

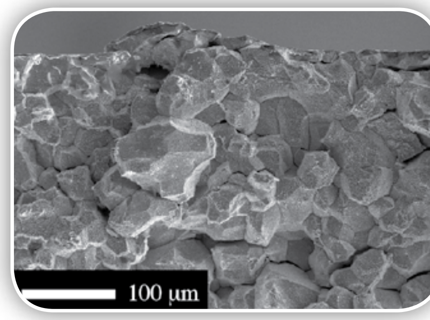
Another project related to concrete aging involves a case study conducted by an EPRI member that had detected leakage and traced it back to the spent fuel pool. The question was whether the leakage was causing structural damage that the operator should be concerned about—an issue that was favorably resolved for that specific plant. Expanding on this experience, EPRI is developing a generic process that the rest of the industry can use to investigate this and similar problems.

"We need to better understand that degradation mechanism and to have some way of inspecting and testing our concrete in those areas to confirm that we don't have a problem in whatever our time frame is," said Gaertner. "We also want to establish a process for dealing with new issues when we discover them."

Cracking in Component Metals

Crack growth in primary system metals is a known problem for nuclear plants and a major target of EPRI research. Two projects being pursued with ORNL, the Pacific Northwest National Laboratory, and the University of Michigan are developing a more fundamental understanding of the mechanisms behind stress corrosion cracking. "As plants age, they accumulate more and more neutron irradiation, which changes the mechanical and corrosion properties of the materials," said Raj Pathania, EPRI program manager. "The goal of this program is to understand the changes that are going on in this material so we can do a better job of predicting degradation and develop methods to mitigate the damage in the long term."





Samples of irradiated stainless steel subjected to stress in high-temperature water in the laboratory can shed light on stress corrosion cracking of the stainless steels used in BWR primary systems. The higher-magnification micrograph shows that intergranular cracking was a key failure mechanism for this sample.

The research is looking at both the nickel-based alloys used in pressurized water reactors (PWRs) and the stainless steel used in boiling water reactor primary systems. The project is using material samples irradiated in the BOR 60 fast reactor under a previous EPRI program—ten different alloys typical of metals used within the reactor vessel, as well as for the vessel itself. The irradiated samples have been shipped to ORNL and the University of Michigan for analysis. The research will apply advanced inspection and characterization methods, including the use of atomic probe tomography to create three-dimensional images of the metal interior at a microscopic level.

"Examining this material with very powerful microscopes—almost at the nanometer scale—we can start seeing what the grain boundaries look like," said Pathania. "We are finding that irradiation causes displacement of atoms, and as a result, the composition of the grain boundary is significantly different from the normal composition of the alloy. This enables a crack to grow more easily into the material." The project is examining both how cracks are initiated and how they then propagate. The analysis will correlate crack initiation and growth with the radiation dose, the stress the metal was subject to in shipping and welding, and the alloy composition.

"With this information, we will be able to find ways to minimize long-term damage," Pathania said. "This may mean you have to change the water chemistry, replace a material with an improved alloy, or do something to protect the material."

Building Confidence

Major capital refurbishment and modernization projects are linked to the expected remaining life of the plant. That is why some nuclear plant owners expect to seek approval for extended operation as early as 2013. The research must start now, as it will take years to gather the data necessary to justify life extension out to 80 or 100 years. The technical basis for extended operation must not only inform the business decision but also satisfy regulatory agencies and the public.

"Public confidence doesn't come overnight," said Shahkarami. "The sooner we start and the sooner we invest the right resources on the right topic, the sooner we build confidence on the part of the public and everyone else that the technology and tools can provide for safe operation beyond 60 years." Mano Nazar agreed wholeheartedly: "The LTO project couldn't come at a better time, as our industry grapples with ways to meet increasing demand for electricity while simultaneously achieving our national goal of reducing greenhouse gas emissions. The technical merit and collaborative structure of the LTO Project will enable the industry to learn and implement best practices and creative solutions that will help extend the life of our plants without compromising safety or the environment."

This article was written by Drew Robb. Background information was provided by John Gaertner (jgaertne@epri.com).

Ceramic Cladding for Fuel Rods

Nuclear fuel rods are exposed to challenging temperature and radiation environments. The conventional zirconium cladding that surrounds the pellets, first introduced about 40 years ago, has undergone continuous improvement and has generally been quite successful. But to increase operational flexibility, ensure high reliability, and maintain safe operation, the LTO Project is investigating new fuel designs. These designs have the potential to increase fuel lifetime by a factor of 2 or more and to completely avoid fuel damage under postulated accident conditions.

One possibility being examined is replacing the zirconium cladding with a ceramic such as silicon carbide (SiC). With zirconium, in the event of an accident, fuel damage and melting might begin at a temperature of 2300°F. The fuel interacts with the cladding, creating exothermic chemical reactions that can lead to melting. Ceramics, however, do not interact with the fuel at those low temperatures. "That would offer a lot of operational flexibility for the plant," said EPRI's John Gaertner. "Cladding that's able to tolerate higher temperatures offers a greater safety margin and could provide more opportunity for power uprates as well."

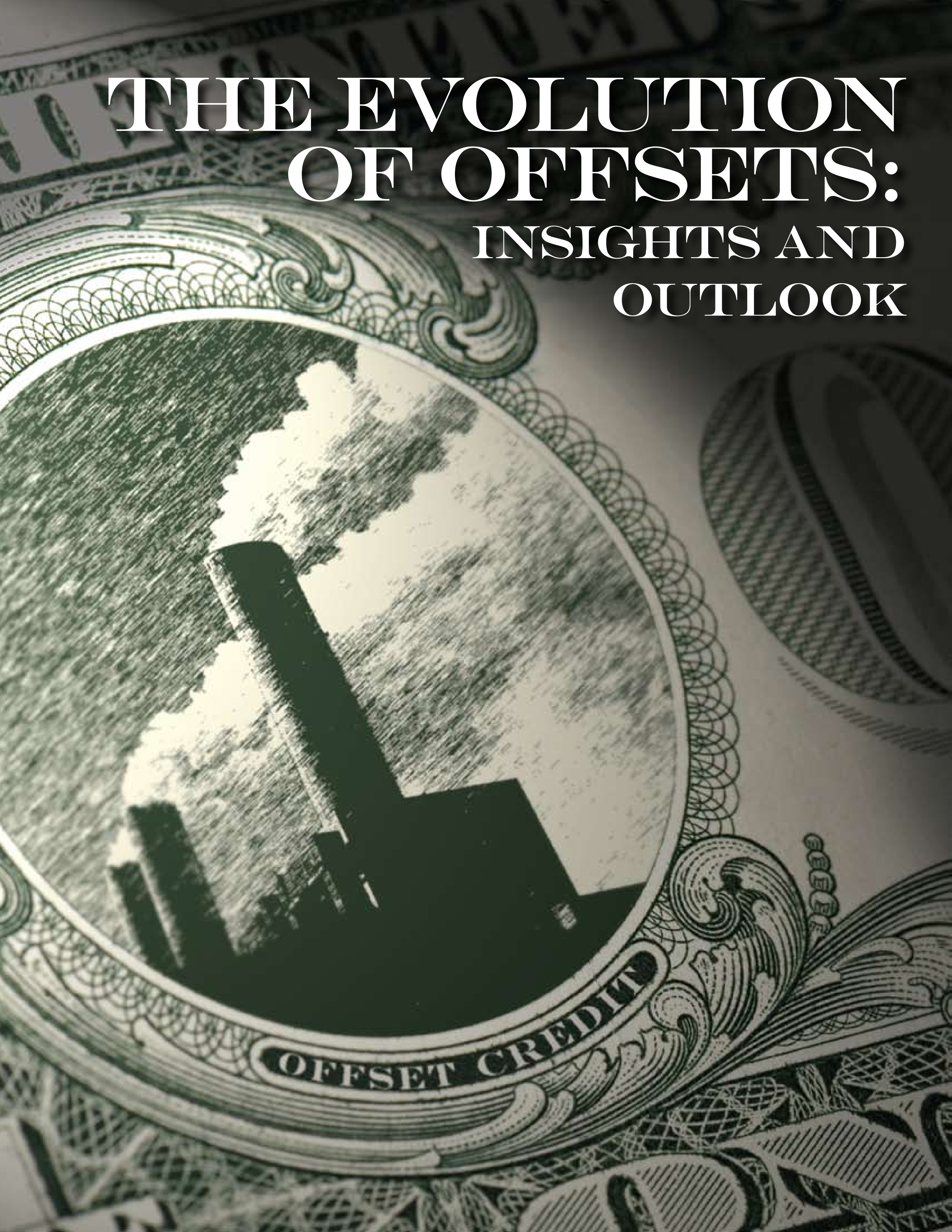
Westinghouse prototype SiC-wound fuel cladding

The research effort consists of irradiating SiC-clad tubing at the Massachusetts Institute of Technology's Nuclear Research Reactor under PWR conditions and then testing the tubing samples to characterize their behavior and mechanical properties. Early tests will focus on the performance of the end caps of the SiC tubes, which are the equivalent of the end plugs and welds for zirconium-based fuel rods.

The goals for the next five years are to test the material under real reactor conditions and to analyze the operational and accident performance of SiC fuel using EPRI's FALCON fuel analysis software code.

John Gaertner is technical executive in nuclear plant technology at EPRI. Gaertner joined EPRI in 1983 as a project manager in the area of risk assessment and management. He left the Institute in 1990 and served as vice president and then senior vice president of ERIN Engineering until returning to EPRI in 1998. He was subsequently program manager for risk and safety and manager of Nuclear Sector operations. Gaertner has a B.S. degree in physics from Indiana University of Pennsylvania and an M.S. degree in atmospheric science from the Massachusetts Institute of Technology.

THE EVOLUTION OF OFFSETS: INSIGHTS AND OUTLOOK



THE STORY IN BRIEF

Emission offsets may substantially reduce the cost to electric power companies and the public of complying with anticipated carbon emission constraints mandated by climate policy. The regulatory framework for greenhouse gas emission offsets continues to evolve, however, and uncertainties remain regarding the quantities and types of offset projects that will be allowed, how offsets will be counted, how they will be issued, and how they might be used for compliance purposes.

As political momentum builds for a federal trading program to cap U.S. greenhouse gas (GHG) emissions, one of the most important unresolved issues is whether provisions will be made to allow credit for verifiable emission reductions—known as offsets—that occur outside the specific economic sectors, activities, and geographic regions covered by the cap-and-trade program. For example, will electricity companies be able to obtain carbon dioxide (CO_2) emission offsets by converting nonforested land to forests, which absorb CO_2 from the atmosphere?

The question is particularly urgent because several kinds of offsets may cost less to implement than reducing emissions directly from power plants or other sources, particularly in the near term. So far, however, there is little agreement among existing and proposed regulatory frameworks about the types and numbers of offsets that should be allowed as part of an overall policy for reducing emissions.

Since GHGs contribute to global climate change wherever they are emitted, the effects of abatement efforts are the same regardless of location. In theory, the least expensive way to reduce atmospheric GHG concentrations would be to encourage investment in emission reduction opportunities wherever they can most readily and inexpensively be achieved. In practice, however, concerns have arisen regarding the potential effectiveness and verifiability of offsets.

"There's a great debate going on about what types of offsets should be allowed in any future climate regulatory regime and how to measure, monitor, and evaluate them," said Adam Diamant, senior project manager in EPRI's Global Climate Research program. "The electric power industry has a direct stake in the outcome because offsets not only can lower the cost of complying with climate policy for both regulated parties and society at large, but also may encourage innovative reduction approaches in economic sectors and geographic regions that would not otherwise be covered by a regulatory program. EPRI is responding to this need by hosting a series of policy dialogue workshops with a diverse group of participants, providing information to electricity companies and others about potential offset projects, and sponsoring fundamental research on some key new opportunities."

Workshops Focus on Offsets

While the electric power industry clearly can benefit from access to GHG emission offsets, offsets will also benefit other entities that may be required to reduce their GHG in the future, such as oil and gas companies, metals producers, cement manufacturers, and pulp and paper companies. Widespread access to offsets will lower emission reduction costs for these organizations. A host of other types of organizations will also be involved in offset programs, including offset project developers, project financiers, and organizations that conduct measurement, monitoring, and verification activities. "If we are to develop a common understanding of how to make offsets work on a large scale, both environmentally and administratively, we must provide a forum for wide-ranging discussions among a broad variety of stakeholders, including representatives of electricity companies, other industries, federal regulatory agencies, financial institutions, offset project developers, nongovernmental organizations, congressional staffs, and academic research groups," said Diamant.

EPRI held three workshops in 2008 and published results from the workshops in *The EPRI Greenhouse Gas Emissions Offset Policy Dialogue: Description of Key Issues in the Design of GHG Emissions Offset Programs* (1015633). A final project report to be published later this year will also cover the 2009 workshops.

The workshops are providing participants with information on the benefits and risks associated with current offset programs around the world. Participants have also discussed design elements that could be used in new offset mechanisms currently under development in the United States. Particular attention has been paid to program designs in various U.S. regional initiatives and proposed federal legislation. For example, the Northeast Regional Greenhouse Gas Initiative (RGGI)—a cap-and-trade program covering electric power plants in 10 northeastern and mid-Atlantic states—recognizes five activities potentially eligible to earn offset credits for project sponsors:

- landfill methane capture and destruction
- reduction in emissions of sulfur hexafluoride (SF_6)

- sequestration of carbon through afforestation (planting of new forests)
- certain end-use energy efficiency projects
- methane reduction from various farming operations

RGGI designates each state's respective regulatory agency as responsible for evaluating specific offset monitoring and verification methodologies. Initially, offsets can only be used to meet up to 3.3% of a covered source's CO_2 emissions in a three-year compliance period, although this restriction may rise under certain limited circumstances.

Seven western states and three Canadian provinces formed the Western Climate Initiative (WCI), with the goal of capping aggregate regional GHG emissions at 15% below 2005 levels by 2020. WCI proposed development of a "positive list" of eligible offset project types, together with protocols to standardize their implementation, and it has recommended that no more than 49% of the region's total reductions in GHG emissions by 2020 be generated by qualifying offset projects and emission allowances from cap-and-trade systems outside the WCI.

Although no federal climate legislation has yet passed Congress, the proposed Climate Security Act of 2007 (frequently referred to as the Lieberman-Warner bill) contained several provisions that are likely to be considered for future climate policy. Four major categories of offset activities were included:

- agricultural and rangeland sequestration and management;
- afforestation and reforestation;
- manure management and disposal; and
- certain other types of specific practices, such as methane capture from nonagricultural facilities.

This proposed legislation also allowed a portion of offsets to be generated internationally.

Identifying Concerns

The EPRI workshops have identified several major concerns related to offset projects that should be addressed by any policy frameworks that are adopted.

Additionality is the degree to which emission reduction benefits attributed to an offset project are *in addition* to those that would have occurred under business as usual. Put another way, an eligible offset project is one that would not have been undertaken in the absence of incentives provided by carbon markets. Most existing and proposed offset programs do not accept reductions in GHG emissions from projects not considered to be additional.

Baselines are necessary to quantify the value of potential offsets and also are essential for determining whether an offset project meets additionality objectives. Specifically, a project's baseline is the schedule of GHG emissions that would have been expected in the absence of the offset project. Although efforts are under way to establish standard methods to determine baselines, many projects are still likely to require significant and specific data gathering and assessment.

Leakage refers to the problem that arises when reductions in GHG emissions achieved by an offset project in one location lead directly or indirectly to a corresponding increase in GHG emissions elsewhere. For example, leakage may occur when a forest is preserved that otherwise would have been logged to supply timber to regional markets; preservation of this forest could lead to increased logging in another forest to make up the lost supply.

Permanence addresses the potential for reversal of reductions in GHG emissions achieved by an abatement project. This concern underscores the need for long-term commitments and verification. Permanence has emerged as a particular issue for agriculture and forest-related projects, where fire, disease, or logging can cause stored carbon to be re-emitted into the atmosphere.

Existing offset programs have generally taken one of two tacks for determining which types of projects may be eligible to earn offset credits. Both RGGI and WCI have developed positive lists of eligible, prequalified project types. Alternatively, the world's largest GHG offset program—the clean development mechanism (CDM), established under the Kyoto Protocol—evaluates and approves offset projects case by case. Both approaches have their supporters and detractors. Some policy makers and environmentalists have expressed skepticism about whether positive lists can sufficiently ensure the integrity of offset

Offset Project Type	GHG Target	Method	Examples
Industrial Processes	HFCs, PFCs, N_2O	Destruction	Destruction or decomposition of HFC_{23}
Energy Efficiency	CO_2, SF_6	Avoided emissions	Efficiency improvements at power plants and aluminum smelters
Renewable Energy	CO_2	Avoided emissions	Wind, biomass, geothermal, and solar projects
Waste Utilization	CH_4	Flaring or conversion to electricity	Landfill gas capture, animal waste digesters
Fugitive Emissions	CH_4	Flaring or conversion to electricity	Repair of leaking pipelines, destruction of coal-bed methane
Fuel Switching	CO_2	Avoided emissons	Conversion or replacement of large power plants
Gas Flare Reduction	CH_4	Capture and conversion to electricity	Capture of excess gas at petroleum production and processing plants
Land Use and Forestry	CO_2, CH_4	Sequestration	Reforestation and afforestation projects

The clean development mechanism (CDM) developed under the Kyoto Protocol describes eight types of projects developing countries can pursue to offset greenhouse gas emissions. Other authorities may favor different choices or approaches. (Source: Point Carbon) projects, particularly with respect to additionality. On the other hand, while the CDM's project-specific approach is potentially more flexible, critics contend that experience with the process so far has revealed it to be inefficient, resource-intensive, and of uncertain effectiveness.

To help electricity companies and other stakeholders sort through the thicket of complex and often contradictory policies affecting offset projects, EPRI has published *A Comprehensive Overview of Project-Based Mechanisms to Offset Greenhouse Gas Emissions* (1014085).

Forest Carbon Sequestration

The difficulties in qualifying and setting up offset programs can be seen in two options that have received a great deal of coverage in the popular press: forest carbon sequestration (FCS) projects and projects for reducing emissions from deforestation and forest degradation (REDD). As the news stories report, establishing new forests or avoiding the loss of existing forests can provide some of the least expensive and largest-scale GHG offsets potentially available, both globally and in the United States. The Intergovernmental Panel on Climate Change estimates that carbon emissions from deforestation account for approximately 20% of annual global anthropogenic GHG emissions. Analysis by the U.S. Environmental Protection Agency of the proposed Lieberman-Warner bill (S. 2191) concluded that by 2020, carbon sequestration in U.S. forests could offset the emission of approximately 300–400 million metric tons of CO_2 annually.

EPRI conducted a study of various FCS options and concluded that they may cost less than one-fourth as much as direct emission controls at power plants. The study has been published in a report, *Guidance for Electric Companies in the Use of Forest Carbon Sequestration Projects to Offset Greenhouse Gas Emissions* (1012576).

In addition to their comparatively low cost, FCS projects may provide power companies with a hedge against changes in fuel costs or electricity prices (since they are independent of generation) and also provide geographic flexibility (since a company does not need to own the forest land involved).

Despite these advantages and practical potentials, universal acceptance of forest projects has been hampered by concerns such as additionality, appropriate baselines, monitoring, verification, leakage, and permanence. As a result, the European Union Emissions Trading Scheme does not recognize offsets from either FCS or REDD projects for emissions compliance. Several design and policy approaches are being explored to address these challenges, but it is not yet clear what kinds of forestry-based activities will eventually be allowed for compliance purposes.

Investing in Offsets

Besides the highly uncertain future regulatory treatment of GHG offsets, power companies and other potentially regulated entities face other risks and practical considerations in setting up offset programs. One key question is ownership. For example, some companies may decide to plant forests on lands they already own or control—an approach that may lower costs and some risks. However, this will require substantial in-house land management expertise, the ability to manage the entire offset development process, and the willingness to take on substantial project and regulatory risks. Few electricity companies today have these capabilities in-house. Also, a company would need to own a great deal of land to generate a substantial number of forestry-based emission offsets, particularly in the near term.

As an alternative, companies may form a consortium to develop offsets and hire managers to implement them. PowerTree Carbon Company, established cooperatively by 25 U.S. power companies to develop forest sequestration projects, is one example. Another approach that several companies are exploring is to invest in the growing number of new carbon funds that invest directly in a diversified set of offset projects and provide offsets to their investor members over time. Still another approach would be to purchase offsets on the secondary market, after they have been issued to projects that have been implemented effectively. Purchasing offsets rather than developing them in-house may be the most flexible and economical approach for power companies and others wishing to make use of FCS, REDD, and other types of GHG offsets.

"Power companies potentially could realize substantial benefit from offset programs, but policies covering them are still evolving," concluded Diamant. "Ongoing EPRI work can help inform offset policy development, provide companies with the data and tools they need to create their own projects or purchase them in the marketplace, and pioneer innovative new techniques to offset emissions in the most cost-effective manner. EPRI plans to stay involved in efforts to improve the measurement, monitoring, and verification of emission reductions achieved through company-sponsored offset projects."

This article was written by John Douglas, science and technology writer, and Adam Diamant, manager of economic analysis in EPRI's Global Climate Research program (adiamant@epri.com).

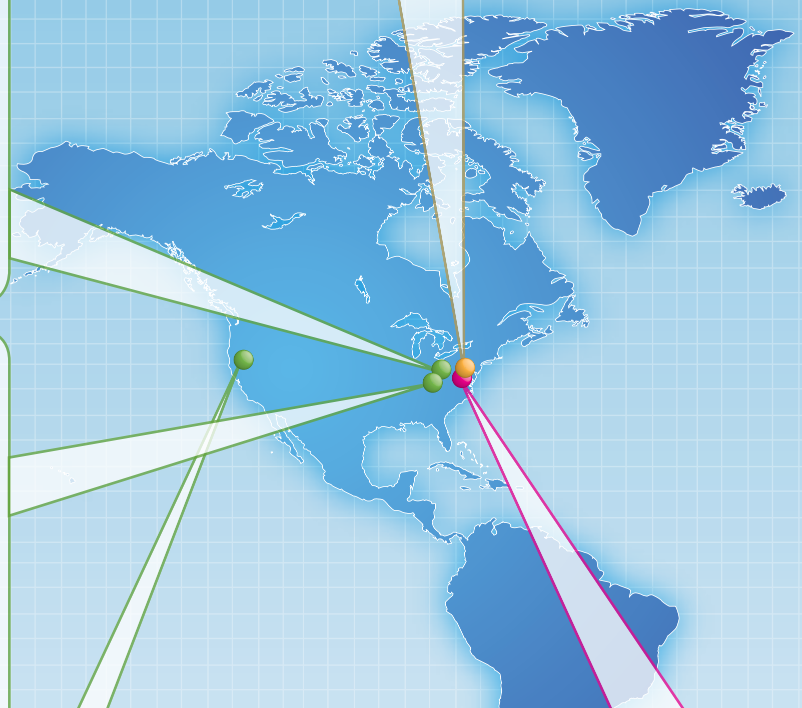
Adam Diamant is a senior project manager in EPRI's Global Climate Change program, focusing largely on GHG emissions trading issues, risk analysis, and emissions offsets. Earlier he headed ecological asset management projects at EPRI Solutions and worked for more than a decade as a private consultant. He has also held regulatory oversight duties in the U.S. Office of Management and Budget. Diamant received a B.A. in political science from the University of California at Berkeley and a Master in Public Policy degree from Harvard University's John F. Kennedy School of Government.

DATELINE EPRI

News and events update

NRC Briefed on Risk Assessments

ROCKVILLE, Md. – Senior Program Manager Ken Canavan participated in a Feb. 4 briefing to the U.S. Nuclear Regulatory Commission on the use of risk-informed, performance-based regulation in the nuclear power industry. Canavan provided EPRI's perspective on the role of probabilistic risk assessments in nuclear plant operations and maintenance and the need to "socialize" risk technology in a manner similar to safety analysis. He also introduced EPRI's risk technology learning pyramid, which could be used as part of the socialization process to convey key concepts and benefits of risk technology to entire organizations, including non-risk professionals.



Conference Looks at Commercially Viable CCS

PITTSBURGH, Pa. – EPRI and a variety of agencies and industries joined the U.S. Department of Energy and the National Energy Technology Laboratory to sponsor a conference in Pittsburgh to focus on carbon capture and storage technologies that could be developed and deployed in North America. Participants shared experiences from around the world, as well as information on progress in developing CCS technologies.

International Conference on Coal Ash Returns to Lexington

LEXINGTON, Ky. – EPRI is sponsoring the poster session for the 3rd biennial World of Coal Ash conference, May 4–7, in Lexington. This international conference is organized by the American Coal Ash Association and the University of Kentucky Center for Applied Energy Research. It focuses on science, applications, and sustainability of coal ash worldwide, encompassing all aspects of coal combustion and gasification products. For more information, contact Ken Ladwig, keladwig@epri.com.

Workshop Looks at Seismic Designs, Issues

PALO ALTO, Calif. – EPRI hosted a workshop in February to examine issues concerning seismic design standards for new nuclear power plants in the central and eastern United States. More than 60 scientists and engineers from utilities, the U.S. Nuclear Regulatory Commission, the U.S. Geological Survey, universities, and research organizations around the world discussed seismic modeling alternatives and identified analytical uncertainties. Results will guide the development of a new seismic source model that will support a stable licensing basis for new plants. The project is part of EPRI's Advanced Nuclear Technology Program and is co-sponsored by the U.S. Department of Energy.

EPRI Receives Grant to Develop Smart Grid Roadmap

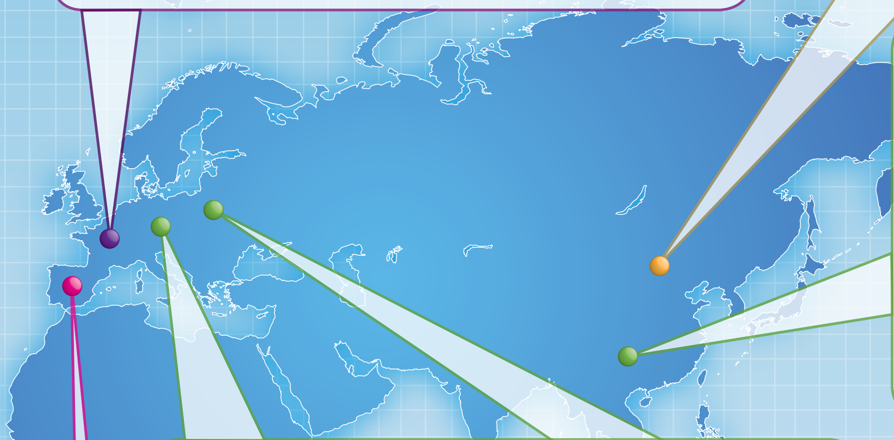
GAITHERSBURG, Md. – EPRI was selected by the U.S. Department of Commerce, National Institute of Standards and Technology, to develop an "interim roadmap" to move the U.S. toward harmonizing interoperability standards for the smart grid. It is intended to ensure that different vendors' products will work together effectively, and that consensus standards can drive down the cost of components and systems, reduce the risk of early obsolescence, and spur innovation. Scheduled to be completed by early summer, it will inventory existing standards, identify gaps, and list priorities for reconciling differences among current standards or developing entirely new ones. EPRI will develop the roadmap to have consensus support of the utility industry, independent system operators, manufacturers, standards development organizations, state regulators, and consumer representatives.

EPRI Directs Weeklong Test of European Data Exchange

PARIS – The Union for the Co-ordination of Transmission of Electricity (UCTE) and EPRI, along with 10 European and American companies, conducted one of the largest tests to date of systems to move and exchange utility operations data for Western Europe's complex transmission system. The weeklong tests were conducted in March at the facilities of RTE France in Paris and focused on data exchanges using the International Electrotechnical Commission's Common Information Model standard. For more information, contact David Becker, dbecker@epri.com.

China Hosts International EMF Seminar

BEIJING – Rob Kavet, EPRI senior program manager for electric and magnetic field research, accepted an invitation from the State Grid Corporation of China (SGCC) to participate in a seminar on EMF issues in China. SGCC's China Electric Power Research Institute hosted the seminar in Beijing in April, where international experts examined a draft national standard for EMF exposure limits and new developments in a variety of research areas. An additional goal was to promote collaboration between China and countries where EMF research is conducted.



China Hosts Global Mercury Conference

GUIYANG, China – EPRI's Leonard Levin and Sharan Campleman will present two papers at the 9th International Conference on Mercury as a Global Pollutant, June 7–12, in Guiyang, China. One paper examines the toxicological interaction between lead and methylmercury. The second paper updates the U.S. mercury inventory. For more information, contact Leonard Levin, llevin@epri.com.

International Electricity Partnership gets CCS Briefing

BONN – John Novak, EPRI's executive director of federal and industry activities for environment and generation, was an observer at meetings of the United Nations Framework Convention on Climate Change in Bonn. Novak presented an update on carbon capture and storage R&D in the U.S. during "A Roadmap to Decarbonizing the Power Sector by 2050," a side event conducted by the International Electricity Partnership, which includes the Edison Electric Institute, Eurelectric, the Federation of Power Companies (Japan), the Canadian Electricity Association, and the Electricity Supply Association of Australia.

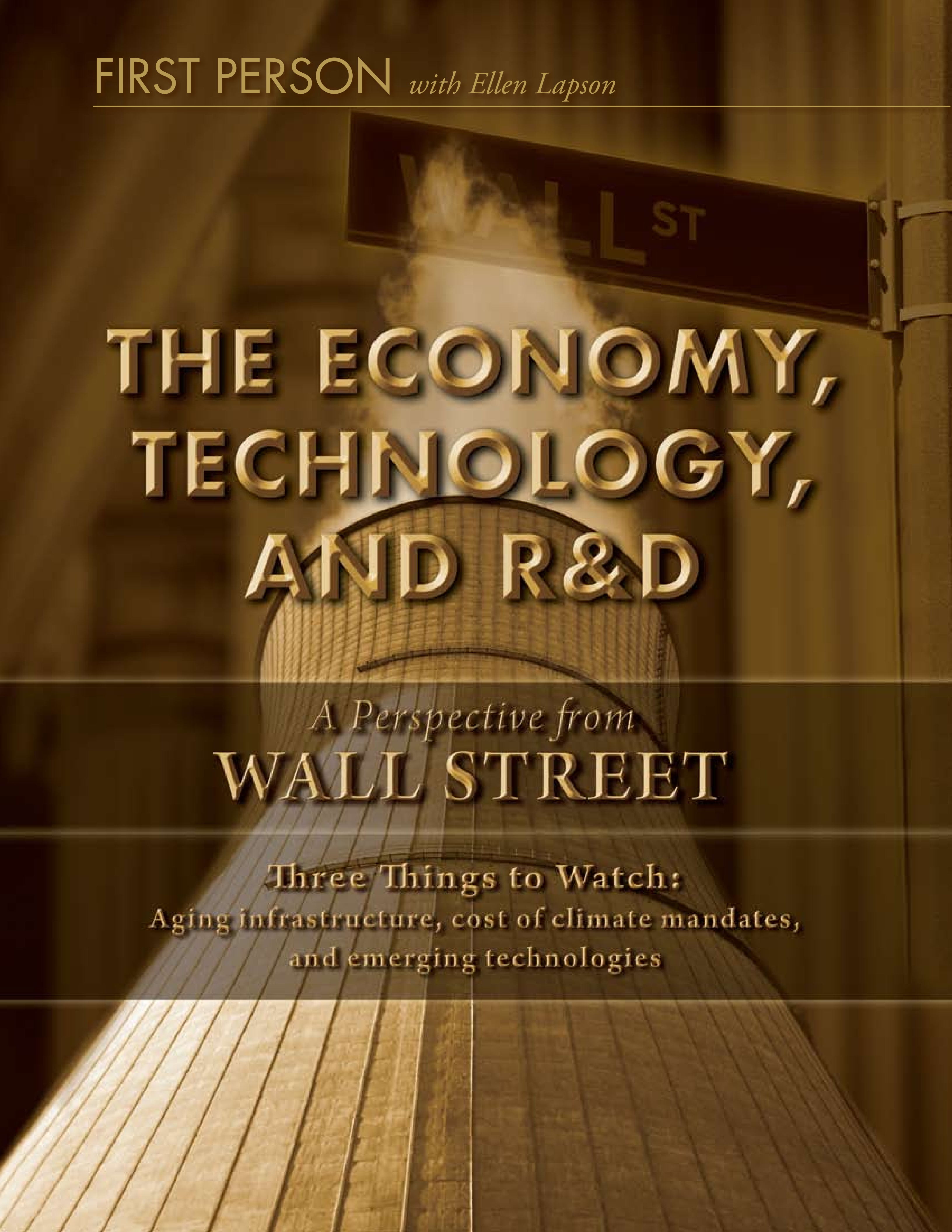
European Workshop to Focus on Grid Efficiency, Losses

WARSAW – EPRI and PSE-Operator will host the International Workshop on Improving Transmission Efficiency, June 2, in Warsaw. This is one of a series of workshops to explore opportunities for reducing transmission losses and develop regional projects to showcase tools and technologies. EPRI's Power Delivery and Utilization sector will host its International Council Meeting in Cracow on June 4 to exchange information and best practices from North America and Europe regarding the smart grid and integrating renewable resources.

EPRI, UNESA Host Workshop on Material Degradation, Mitigation, Inspection

MADRID – EPRI and the Spanish utility consortium UNESA coordinated a multi-utility workshop in Madrid to discuss material degradation and inspection issues in light water reactor nuclear plants. The workshop identified areas where U.S. and European experience overlaps and where collaborative research could lead to better understanding and a broader array of mitigation and inspection options. The workshop also focused on component aging management and how inspection and mitigation strategies can support long-term operation of the nuclear fleet.

FIRST PERSON *with Ellen Lapson*



THE ECONOMY, TECHNOLOGY, AND R&D

A Perspective from WALL STREET

Three Things to Watch:
Aging infrastructure, cost of climate mandates, and emerging technologies

Ellen Lapson is a managing director of Fitch Ratings Global Power Group. She participates in rating U.S. and international electric utilities, energy marketers, project financial transactions, and structured finance based on utility tariffs or contracts. She is also a member of Fitch's Corporate Rating Policy Committee. She is a chartered financial analyst and a member of the Wall Street Utility Group.

Lapson chairs EPRI's Advisory Council, to which she was first appointed in 2004. This 30-member council helps EPRI meet its mandate to serve the public benefit and deliver research that is balanced and relevant in addressing the needs of electricity providers, customers, and society. The council draws its members from utility regulators, environmental groups, finance, academia, and other areas.

In this interview with the *EPRI Journal*, Lapson discusses the economy, investment and regulatory climates, and the role of EPRI's research, development, and technology demonstration portfolio in the years ahead.

EJ: How does the financial sector evaluate the potential strengths and vulnerabilities of electric utilities from the perspective of technology?

Lapson: Let me give you the following context. The electric utility sector is one of the most capital-intensive sectors in the U.S. economy. Large amounts of money must be invested in network and generation assets. Universal electric service would not be affordable without a significant part (more than 50%) of the funding for the industry coming from debt capital rather than from more-costly common stock capital. Another factor that makes electric service affordable is the ability to recover the investment slowly over long physical and economic lives of the assets—20 to 40 or, in some cases, 60 years.

So, the implication is that new technologies are scary to conservative investors in utility debt and equity. Investors fear the emergence of disruptive technologies that could totally change energy economics and render obsolete their long-term investments in utility assets. Such investors hope that the utilities they invest in will incorporate new technologies gradually, just enough to avoid becoming obsolete, and only after those technologies have proven to be commercially viable.

"Funding for demonstration projects and early commercialization is hard to get, and I would say that is a crucial element right now."

There are smaller amounts of money available to fund the development of interesting new technologies at earlier stages from investors who have a greater tolerance for risk. R&D-stage development is funded entirely with equity, either by large corporations investing in a research portfolio or by a hopeful inventor and his friends and relatives.

Another important source of funding is federal or state government grants or loans. As the technology moves from pure R&D into applied development and then demonstration, it becomes gradually more attractive to sources of private equity such as venture capitalists and public offerings of equity. It is only when the technology has been proven in demonstration projects and has shown its merit at commercial scale that it can begin to cross over and attract mainstream sources of debt and equity capital.

EJ: From your perspective on EPRI's Advisory Council, what primary contributions must research and development make to keep utilities economically viable?

Lapson: Mainstream investors in utility securities currently are concerned about three issues that could affect the electric utility sector: first, in the short run, maintaining the performance of aging infrastructure and keeping old systems running at low cost; second, making good decisions about the enormous cost of mandates related to climate change (for example, with regard to coal-fired power plants and massive investments in new meters and delivery infrastructure); and third, limiting longer-term risks of declining demand due to the emergence of new distributed power technologies or energy efficiency devices—emerging technologies that would make obsolete existing investments in transmission, distribution, and central station power generation.

> "Without strong incentives from regulators that set electricity rates, mainstream investors in utility debt and equity generally only want to invest in proven technologies."

RD&D is helping utilities most obviously with the first two problems. Investors can look to research applications that permit utilities to manage these enormous transitions more gradually, avoid making ruinously large investments to replace all their current generating assets, and enhance the value of existing transmission and distribution assets.

Investors also would be highly interested in demonstrations of cost-efficient and reliable forms of carbon capture and storage (CCS), but so far they are skeptical that all the regulatory, legal, and technical challenges of CCS can be mastered, especially given the strong political hostility toward coal.

With regard to the third risk, potential declining demand for central station–generated power distributed over a network, investors are interested in the potential of electric cars, because demand from automotive charging would offset anticipated declines in demand from other end uses as consumers and industries adopt more-efficient devices.

EJ: What is the "chicken-and-egg" in technology advancement? Capital? Regulatory and economic incentives? Research and development? Which comes first?

Lapson: The R&D process relies on modest amounts of federal and state government funding as well as funding from large manufacturers and utilities. Regulatory incentives from state utility commissions and state and federal loans or grants are then needed to bring about the initial pilot and demonstration projects. The move from a successful first demonstration to deployment is where the financial risk can be reduced by regulatory and tax incentives (investment tax credits, production tax credits, and accelerated depreciation, for example).

With its collaborative approach that allows utilities to combine their individual spending into more meaningful sums, EPRI has been instrumental in making industry technology investments more efficient. But the amounts that the electric utilities are now willing to dedicate are too small a percentage of the industry's revenues; there is a view that it may be necessary for the government to impose a charge on electricity customers to fund development, demonstration, and deployment of promising technologies.

Alternatively, state public utility commissions could allow a larger percentage of revenues to be spent by utilities on a portfolio of RD&D projects, with that spending made more effective via EPRI's collaborative model.

Many promising technologies have been brought to a precommercial stage over the past 20 years and now need to be demonstrated and deployed at commercial scale. Funding for demonstration projects and early commercialization is hard to get, and I would say that is a crucial element right now.

EJ: EPRI and its members initiate research and development to address long-term issues. The same is true of the financial sector. Based on your experience in the financial sector and as a member of EPRI's Advisory Council, are the technologists and the financiers seeing the same future?

Lapson: Many of EPRI's programs are oriented toward application of technologies that have already been researched by others. A good many EPRI programs relate to maintaining and improving the performance of aging power plants, distribution systems, etc.

All of these activities reflect the focus of utility managements, utility rate-setting commissions, and mainstream utility equity and debt investors—all oriented toward optimizing the short- and intermediate-term economic performance of utilities.

Two parts of EPRI's program stand out for me as having a different orientation. First is the Technology Innovation program, which seeks promising technologies for future application in the industry. Second is the work that EPRI is doing to evaluate future power generation and energy efficiency options. EPRI is increasingly respected as a source of unbiased technical evaluation of our future power options.

EJ: Do executives and financiers view research and development as important in addressing technological uncertainty and financial uncertainty? What role, if any, should research and development serve in making decisions about major capital expenditures?

Lapson: As I mentioned earlier, making the right choices in future power generation and energy efficiency technologies will be tremendously important. EPRI's work to define the likely costs and contributions of these technologies is quite important to the U.S. Congress and to state governments in sorting out competing policy options that will drive huge capital spending decisions. I am very proud of the role that EPRI is playing and will play in providing sound estimates and projections to steer the debate away from dogma and toward more enlightened economic decision making.

EJ: What gives the financial sector confidence that a particular utility or technology strategy is sound and could lead to a good use of capital?

Lapson: Without strong incentives from regulators that set electricity rates, mainstream investors in utility debt and equity generally only want to invest in proven technologies—those that have already been demonstrated at commercial scale and are accompanied by meaningful warranties of performance by strong creditworthy manufacturers.

The only exception is if regulators will authorize in advance the recovery of investment in new technology without subsequent disallowances if the outcome proves to be less than hoped. State laws in Florida, Virginia, and Iowa, for example, permit the state regulators to provide investors with assurance of long-term investment recovery for major power generation investments.

EJ: Could a prolonged recession or period of slower economic growth impede the current momentum for research and development in the electricity sector?

Lapson: Yes, that is possible. A problem that faces us is that declining or slowing demand for electric power, combined with significantly lower natural gas prices, will cause some people to revert to the convenient belief that we can rely upon relatively cheap natural gas power generation to lower carbon emissions and to replace coal generation.

In my opinion, this is a dangerous assumption and not a worthy public policy. New shale gas production and recessionary demand reductions will boost natural gas supply relative to demand for a while, but then we will face declining production curves once again, and that could lead us into another period of gas price spikes in the next decade.

EJ: Do you see any technologies or broad areas of technology with the potential to be "game changers" in the utility industry?

Lapson: Energy efficiency that lowers demand materially. Distributed generation at substantially lower cost than at present. A breakthrough in transmission efficiency or large-scale battery storage.

EJ: Are there fundamental strategies such as fuel diversity that R&D should support? From the financial sector's perspectives, what are those fundamental strategies?

Lapson: From the public policy perspective, more efficient end-use devices would lower demand, and there is every evidence that this is a lower-cost strategy relative to every form of new power supply. Utility investors could be spared the financial losses that would result from funding enormous investments in new generation or transmission capacity that later prove to be unnecessary due to greater consumption efficiencies.

Fuel diversity has been demonstrated to lower risk under a variety of circumstances, such as supply constraints, price spikes, international turmoil, terrorism, etc. Resolving the back end of the nuclear fuel cycle, whether by long-term storage or reprocessing, would help the public to adopt nuclear generation more widely and would be a major advance.

CCS technologies would permit the continued use of domestic coal resources and in the longer term would support the reduction of carbon emissions from natural gas–fired generation.

Efficient, low-cost transmission technologies, battery storage systems, and controls to deal with intermittent power supply are essential if we are going to integrate larger amounts of wind power in our energy supply.

"It is only when the technology has been proven in demonstration projects and has shown its merit at commercial scale that it can begin to cross over and attract mainstream sources of debt and equity capital."

Renewed Interest in
Reducing Heat Rate

More Power from Less Heat

The heat rate of a coal-fired power plant measures the amount of heat, typically in Btus, needed to generate 1 kilowatt-hour (kWh) of electricity. Accordingly, typical units for heat rate are Btu/kWh. Reducing a power plant's heat rate can lower fuel consumption and costs, directly benefitting power producers and their customers. For example, at a typical 500-megawatt (MW) plant operating at 90% capacity factor and firing $2.00/MBtu bituminous coal, a mere 1% heat rate reduction will save about $800,000 in annual fuel costs. Such heat rate improvements can often be achieved simply by recommitting to best operating practices, without the need for capital expenditures on new technology.

THE STORY IN BRIEF

Improving heat rate has traditionally provided electric utilities a means to improve the efficiency and lower the operating costs of their coal-fired generating plants. Today, pressures to reduce plant emissions and prepare for potential carbon dioxide emission regulations are encouraging utilities to take a fresh look at this proven, economical option. EPRI research is helping utilities to identify and evaluate operational improvements and capital investments that could lower a plant's heat rate.

Some plant operators have not focused on heat rate reduction programs because of legitimate but conflicting concerns. For example, because grid operators have made availability paramount, power plant operators have historically focused resources on ensuring plant availability, making heat rate improvement a lower priority. Environmental controls also tend to work against a plant's thermal efficiency. Selective catalytic reduction and scrubber systems add parasitic loads, which reduce plant efficiency from the original design; and the combustion staging and overfire air techniques widely used for the reduction of nitrogen oxides force the boiler into a non-optimal operating mode, decreasing boiler efficiency and increasing plant heat rate.

Concerns about triggering a New Source Review may discourage plant owners from pursuing capital-intensive improvements that could reduce heat rate but also entail significant redesign of plant components such as condensers, cooling towers, and turbine generators. Fuel adjustment clauses in utilities' rates that allow regulated companies to pass through fuel cost increases may also blunt the incentive to reduce fuel consumption.

A Wealth of Advantages

Despite these competing concerns, recent developments have revived interest in heat rate reduction. First, U.S. coal prices reached historic highs in 2008, and even with substantial moderation resulting from the current financial downturn, coal prices remain above historic averages. Second, U.S. power companies are coming under pressure to reduce all power plant emissions, including carbon dioxide (CO_2), ahead of the deployment of carbon control technologies.

Heat rate improvement is an ideal way to start this reduction. It is commercially proven and is the most cost-effective and immediately available control process for lowering CO_2 on the margin. The 1% heat rate reduction described in the example above corresponds to a 1% reduction in CO_2 emissions—about 40,000 tons/year—which could amount to significant savings if new regulations permit trading of CO_2 credits or impose a "fee" on CO_2 emissions. Even assuming the eventual implementation of carbon capture and storage technologies, optimizing heat rate still makes sense as a first line of CO_2 reduction and to complement other control options that may emerge.

Heat rate reductions can also help plants meet other emissions requirements, by lowering emissions such as nitrogen oxides, sulfur dioxide, particulates, and mercury. Even if the quantity of pollutant released from each ton of fuel remains constant, an improvement in heat rate will reduce the amount of fuel burned and thereby lower the total production of a given pollutant. In many cases, the benefit of emissions reductions can exceed the value of fuel savings.

In competitive markets, plants with improved heat rates can earn a better position in the dispatch order. With the recent drop in natural gas prices, superefficient combined-cycle units are competing with some of the less efficient coal units that have high fuel expenses and emissions penalties. Lower gas prices also reduce the market price for power, forcing independent power producers to look for ways to optimize power production costs.

Assessing Costs and Benefits

EPRI's Production Cost Optimization (PCO) project is helping utilities improve heat rates at their plants and address the various competing concerns. Phase 1 of the project, started in 2006, assists plants in re-implementing or enhancing their heat rate programs through on-site plant assessments and recommendations for operational changes. Phase 2, begun in 2008, helps operators identify and prioritize capital projects that will lower heat rate.

Phase 1 provides independent, third-party assessments of heat rate issues at participating units. The assessments rank the potential benefits and costs of efficiency-boosting operational changes, which can be used by management as a basis for investment. This objective analysis can help to address some of the competing concerns or disincentives that might otherwise stand in the way of heat rate improvement efforts.

"The assessments focus on those changes that can achieve significant improvements in efficiency losses, that can be most easily implemented, and that can be sustained over time," said Jeff Stallings, one of the EPRI managers for the PCO project. "Participants in the EPRI project commit to achieving at least 1% heat rate reduction at each unit."

Participation in the project begins with an analysis of plant historical data and design information. The current thermal performance is calculated to establish the project baseline. Next, EPRI coordinates a team of heat rate experts in an on-site performance appraisal. This includes interviews with key plant personnel to identify potential areas for improvement in their heat rate programs. Particular attention is paid to the methods used to identify subpar performance, the plant staff's responsiveness to issues that arise, and other areas that may need attention if plant performance is to be optimized. To assess the plant's layout and physical condition, the team conducts a "walk-down" of plant equipment to identify problems with instrumentation, review the alignment of those valves critical to optimizing plant performance, and confirm proper operation of plant equipment.

Once the data collected during the site visit have been analyzed, the project team prepares a confidential appraisal report that includes the following elements:

- an overview of performance;
- heat rate comparisons to baseline;
- prioritized recommendations for improving and optimizing performance; and
- estimated costs and projected heat rate savings for each recommendation.

After the improvements are made, the team returns to the site to verify the resulting heat rate reductions. The long-term goal is a sustainable heat rate program that preserves the advances made, prevents performance deterioration, and continues to identify improvement options.

Results and Recommendations

To date, nine plants have completed on-site assessments, and eight of them have received their completed analyses and reports. Four additional plants are scheduled for assessment in 2009. The units assessed represent a wide range, with service ages from 27 to 54 years, plant capacities from 75 to 729 MW, and a variety of boiler and turbine types.

The plant assessments identified several problems that could be addressed widely across the industry. For example, many of the plants were found to be experiencing combustion-related problems, such as high furnace exit gas temperatures (FEGTs). Few of the plants carried out regular performance testing of individual equipment or of the unit as a whole. In general, information on heat rate was not readily available to plant workers—a shortcoming that undermined attempts to bring a sharp focus on improvement.

In light of these and other observations, the assessment team made five common recommendations to the eight plants.

- Initiate a program of unit optimization and routine diagnostic testing.
- Improve combustion optimization and address high FEGTs.
- Improve monitoring of feedwater heater performance.
- Improve availability of heat rate information to plant personnel.
- Improve operator use of available heat rate information, including monitoring controllable losses.

The on-site assessments combined these and other site-specific recommendations to produce estimates of heat rate improvement for each of the first eight units participating. The unit with the smallest potential for heat rate improvement could realize a 2% improvement, and the unit with the greatest potential could expect a 4% improvement. The average potential heat rate improvement was 3% for the eight plants, or approximately 300 British thermal units per kilowatt-hour (Btu/kWh). For the eight units combined, this would produce estimated annual fuel cost savings of $2 million. The five common recommendations represent 50% of the total potential heat rate improvement for these units.

To date, participating utilities are in the early stages of implementing the recommendations, and no quantified benefits are available. After the recommendations are implemented, additional plant data will be analyzed, and the heat rate improvement attributable to each recommendation will be calculated.

Prioritizing Capital Improvements

Phase 2 of EPRI's PCO project looks at capital projects that could improve heat rate. "These initiatives require 'bigger bucks' than the phase 1 efforts, but they also hold the promise for a 'bigger bang' in terms of potential pay-off," said Sam Ko-rellis, who co-manages the PCO project. "To commit to one of these projects, utilities need a cost-benefit analysis of potential projects and a hierarchical ranking according to expected benefits."

For this phase, EPRI's project team developed a methodology to assess the net annual benefit of potential capital improvements, with the goal of compiling enough cost-benefit information to enable utilities to rank capital projects for individual plants.

The team developed a list of potential capital projects that could improve the performance of the major systems in a typical solid fuel plant. They then calculated the costs and benefits of each project and integrated the information in a spreadsheet. The spreadsheet allows inputs to be modified according to a plant's size and configuration, making it possible for individual utilities to use the methodology for scoping studies.

For each capital project, the spreadsheet includes a description of the project, its purpose, the circumstances that qualify a plant for the project, and industry experience with the project. The cost data are broken out into capital investment, operating costs, and maintenance costs, and availability and reliability issues are summarized for each project. The spreadsheet quantifies a project's expected benefits in terms of improved heat rate, reduced auxiliary power, increased capacity, improved equivalent forced outage rate, reduced emissions, and added power sales. The bottom line is the net annual benefit, which is the difference between the benefits and the costs.

An initial set of calculations, developed in 2008, considered 25 potential capital projects applied to a hypothetical 500-MW coal plant. Among the projects were turbine steam seal upgrades, turbine section replacements, use of "intelligent" sootblowing systems, condenser retubing, upgraded air heater seals, application of variable-frequency-drive motors, and use of closed-loop combustion optimization software. The cost-benefit results for these varied widely, and the realistic tone of the analysis was reflected in the fact that not all projects considered for this generic unit produced net benefits with a positive payback. Heat rate reductions ranged from 0.10% to 2.5%; projected net benefits ranged from \$35,000/year to \$6.2 million/year. This guide can be used by plant engineers and planners to develop a realistic case for making specific capital investments.

EPRI will refine and expand the spreadsheet of capital projects in 2009 and develop a new guide for major maintenance projects, such as air heater cleaning, repair of leaking cycle isolation valves, and overhauls of turbines, pumps, and pulverizers.

"Improving heat rate is not new, and it's rarely about technology breakthroughs," said Stallings. "But with the economic downturn and the growing pressure to control CO_2 emissions, more plants are going to be looking for ways to increase efficiency, and we can help them analyze and choose the best paths."

Korellis also noted, "By developing standardized project evaluation guidelines and conducting site appraisals, we are providing the tools for power plant owners and operators to apply this knowledge to their fleets and optimize their operating costs."

This article was written by Jonas Weisel. Background information was provided by Anthony Facchiano (afacchia@epri.com), Jeff Stallings (jstallin@epri.com), and Sam Korellis (skorellis@epri.com).

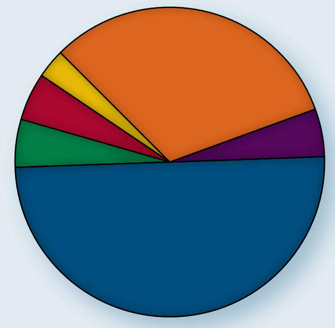
Heat Rate 101

Heat rates are the "gallons per mile," or fuel consumption rates, for specific levels of power plant output. Heat rates are also the inverse of plant efficiency. In this sense, they are comparable to a golf score: lower is better.

The heat content of coal is 8,000 to 12,000 Btu/lb. Coal costs \$1–\$2/million Btu, or about \$30/ton. A typical 500-MW coal plant consumes 6,000 tons per day at full load. For a typical coal-fired plant, fuel is by far the largest expense, representing about 55–75% of total plant expenses.

For each power plant, the heat rate depends on the plant's design, its operating conditions, and its level of electric power output. In theory, 3,412 Btu of thermal energy is equivalent to 1 kWh of electric energy. For existing coal-fired power plants, 10,500 Btu/kWh is a typical heat rate.

Typical expenditure of energy from fuel burned in a coal-fired plant



Electricity to grid	32%
Auxiliary power	5%
Heat to cooling water	50%
Heat out the stack	5%
Energy used on conversion	5%
Lost energy	3%

Anthony Facchiano is the technical lead in EPRI's Combustion Performance and NOx Control program, focusing primarily on NOx control technologies and boiler operability and performance issues. Before joining EPRI in 1993, he worked at Coen Company, Bechtel Power Corporation, and Exxon Research and Engineering. Facchiano received a B.S. degree and an M.S. degree in mechanical engineering from Manhattan College.

Jeff Stallings is a senior project manager in EPRI's Combustion Performance and NOx Control program, where his work focuses on plant heat rate, intelligent sootblowing, burner diagnostics, and combustion optimization. Prior to joining EPRI over 20 years ago, Stallings worked at SRI International and at Energy Incorporated. He is a registered Professional Engineer with a B.S. in chemical engineering from Princeton University, a masters in international studies from Johns Hopkins University, and an M.B.A. from University of California at Berkeley.

Sam Korellis is a senior project manager in EPRI's Combustion Performance and NOx Control program, where his work focuses on plant heat rate, coal and air flow, and NOx reduction. Korellis worked 30 years for power generation companies across the United States. He served as an officer in the American Society of Mechanical Engineers, working on codes and standards with a focus on performance test codes. Korellis is a registered Professional Engineer and earned B.S. and M.S.M.E. degrees from Purdue University.

Can Utilities Harvest Emissions Reductions on the Farm?

Concerns over greenhouse gas (GHG) emissions have focused mainly on carbon dioxide (CO_2), largely because of its current high level of atmospheric concentration. But CO_2 is not the only GHG. Methane, nitrous oxide, sulfur hexafluoride, and a number of other gases also absorb and re-emit infrared radiation into the atmosphere, potentially contributing to global warming. In fact, while present in the atmosphere in much lower volumes than CO_2, many of these less discussed GHGs are—molecule for molecule—more potent warming agents.

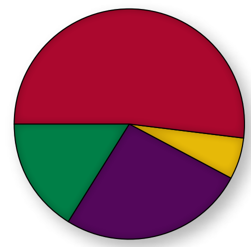
Nitrous oxide (N_2O) is a powerful greenhouse gas, with an atmospheric lifetime of 114 years and a global warming potential 296 times greater than that of CO_2. About half the world's emissions of N_2O come from agricultural soils, where they are formed by the breakdown of nitrogen-based fertilizers. Controlling emissions from this source could be a valuable GHG compliance option for power companies, with a potential to offset a portion of power plant CO_2 emissions, which are more difficult and expensive to control (see "The Evolution of Offsets: Insights and Outlook," page 14).

Innovative Field Research Looks at Fertilizers, Crops, and Potential Cooperation Between Utilities and Farmers

To help companies explore this innovative opportunity to generate GHG emission offsets, EPRI has been sponsoring research at Michigan State University on reducing N_2O emissions from agricultural crop production. The work focuses on demonstrating the potential for electric companies and others to work with farmers in their service areas to achieve large-scale, cost-effective GHG emission offsets by judiciously reducing the application of fertilizer without affecting crop yields. If successful, the approach could be introduced worldwide, substantially broadening the offset options available to power producers and others.

The underlying scientific concept is that N_2O emissions from fertilized agricultural fields increase exponentially with increased fertilizer application, while crop yields essentially level off despite higher rates of application. This creates the potential to reduce N_2O emissions substantially by decreasing fertilizer use, with only a minor impact on crop production. Specific objectives of the new research are to evaluate the environmental and economic benefits of lowering nitrogen fertilizer use and to confirm through field tests that crop yields will not suffer as a result. Quantitative models are being developed to predict the relationship between N_2O emissions and crop yields in major cropping systems. Early modeling indicates that reducing fertilizer application can lower N_2O annual emissions by an amount equivalent to about 0.5 metric tons of CO_2 per acre, at comparatively low cost. Additional potential benefits include reduced nitrate runoff from agriculture, leading to improved water quality.

Global Sources of Anthropogenic N_2O



Promise for Offsets

National climate policy and decisions on emission reduction mechanisms are still in the early stages of development, and there is little regional, national, or international consensus on what approaches will qualify for offset credits. For several reasons, agricultural N_2O reduction stands a good chance of being recognized for compliance purposes. Projects to reduce N_2O would not suffer from the concerns over permanence and leakage that plague forest carbon sequestration projects and other types of agricultural offset projects because the GHG emissions are actually avoided rather than merely stored (as CO_2 is in trees), reductions are permanent. And since there is little or no crop loss associated with the reduced emissions, there is no demand-driven incentive to change production practices so that reduced fertilizer application at one farm would lead to increased fertilizer application or crop production at another.

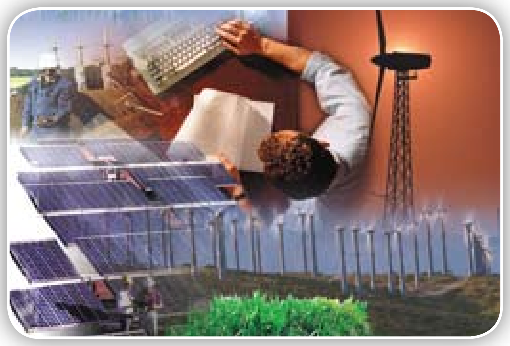
Besides sponsoring the technical research, this EPRI project is exploring ways to strengthen mutually beneficial partnerships between electric companies and the agricultural interests in communities they serve. As part of this effort, EPRI is identifying socioeconomic factors that may discourage farmers from participating in N_2O emission reduction projects and incentives that may encourage them to change their minds.

For more information, contact Adam Diamant, adiamant@epri.com, 510.260.9105.

Custom PRISM Analysis Helps Oglethorpe Plan for Climate Policy

In 2007, EPRI's PRISM analysis illustrated the U.S. electricity sector's potential to reduce overall CO_2 emissions by deploying a portfolio of advanced power generation and related technologies.

As the nation's largest power supply cooperative, with 1,501 megawatts of coal-fired generating capacity, Oglethorpe Power Corporation (OPC) recognized the need to evaluate its own exposure to future mandatory carbon constraints and spoke with EPRI about how PRISM might be applied at the company level. In response to Oglethorpe's interest, EPRI developed the new Company PRISM Analysis, which highlighted the challenges OPC could face in dealing with the climate change issue and provided OPC with an analytical tool for planning its generation portfolio. OPC's PRISM also provided a way to review its R&D priorities and discuss mitigation options with its board of directors and other stakeholders.



EPRI's Company PRISM Analysis quantifies the challenge that an electricity company may face if new laws or regulations require it to reduce its CO_2 emissions beyond business as usual. The analysis identifies CO_2 abatement activities that can help meet future limits on CO_2 emissions and quantifies potential reductions that can be achieved through such options as low-emission technologies and the purchase of emission allowances and offsets.

Defining the Compliance Gap

The analysis first establishes a corporate business-as-usual emissions trajectory based on the company's existing generation fleet and any planned new power plant construction or retirements. This trajectory is then compared with emission levels that might be required under one or more climate policy proposals.

The resulting "compliance gap" indicates the level of reduction in CO_2 emissions the company will need to achieve through a combination of abatement actions and market purchases of emission allowances and offsets. By applying assumptions about the future price of CO_2 emission allowances to the anticipated compliance gap, the company can gain insights into potential compliance costs, assuming that proposed policies will not dramatically impact dispatch of existing and future company power plants. EPRI recently expanded the Company PRISM Analysis to include a new analysis called Compliance Optimization 2.0—known as $CO_{2.0}$—which considers how the dispatch of a company's power plants also might change with the imposition of stringent climate policies.

Acting on Results

For OPC, the Company PRISM Analysis showed that future climate policy could result in a significant CO_2 compliance gap. "We could be facing enormous financial and technical challenges with potential climate change regulation or legislation," said Doug Fulle, OPC's vice president of environmental affairs. "It's a really big issue for us."

The analysis identified potential options for closing OPC's compliance gap and provided insight into the value of adopting advanced generation technologies when they become available. The results of the analysis were presented to Oglethorpe's board of directors as part of an ongoing dialogue about the climate change issue, and the board subsequently agreed to help fund three major EPRI demonstration projects aimed at reducing CO_2 emissions from coal plants: Ion Transport Membrane for Low-Cost Oxygen Production, Post-Combustion CO_2 Capture Retrofit, and IGCC With Carbon Capture and Storage. The board also approved OPC's participation in a Georgia reforestation project and is considering funding for additional EPRI projects.

A more detailed description of the Company PRISM Analysis and its application is presented in the EPRI technical report *Understanding the Impact of Climate Policy on Electric Company Compliance and Investment Decisions* (1015635), published in December 2008. A major conclusion of the report is that many coal-dependent generating companies could face major CO_2 compliance gaps and may have to purchase significant emission allowances and offsets to comply with potential climate policy constraints. In addition, companies may find it worthwhile to invest in retrofit technologies to keep existing coal plants in operation. Specific investment decisions will depend largely on the stringency and timing of policy constraints, as well as on expectations about natural gas prices. Electricity companies' approaches to compliance will also vary widely among regions of the country.

For more information, contact Adam Diamant, adiamant@epri.com, 510.260.9105.

Climate Policy and Retrofit Investment in Fossil Generation: Determining if a Unit Is Investment-Worthy

Owners of coal-fired generation plants face hard choices when new federal or state environmental regulations require additional emission controls. Experience with controlling sulfur dioxide, nitrogen oxides, and mercury shows that retrofit options may be limited and costs can be staggeringly high, especially with older, relatively small plants.

Complying with expected regulations on carbon dioxide (CO_2) emissions is certain to be even more difficult. Considering the likelihood that CO_2 retrofits will require a million dollars or more of investment per megawatt of capacity, it will be crucial that operators have a good understanding of the investment worthiness of their retrofit candidates. Failure to install the controls may severely curtail operations or force units to be retired. The basic question is whether the cost of a unit's retrofit is justified by the future value of its output.

EPRI is launching a new project to provide information that will enable a utility to conduct a market-based assessment of how much investment its retrofit candidates can support, measured in dollars per kilowatt, and how the investment worthiness of a unit may change with respect to climate policy choices and natural gas prices. The study will help companies make informed decisions and quantify the potential value of retrofit investments so decisions can be communicated meaningfully to stakeholders.

Engineering and technology assessments are necessary to assess the retrofit cost, but the owner must also assess the unit's role in its power market and how that role changes with climate policy or with swings in natural gas prices. Currently it is not clear how stringent the national policy to limit CO_2 emissions may turn out to be. Retrofit costs under an aggressive policy could completely undercut the benefits of keeping a unit compliant.

Custom Analysis

The analysis will be based on EPRI's Regional Power Market Analysis framework, which is widely used to evaluate the impacts of climate policy at the individual utility level. It entails a detailed bottom-up simulation of a regional power market that calculates the annual distribution of market prices, CO_2 emissions, and the cash flows ascribable to each generating unit in the stack. EPRI works with the participating utility to specify its generation mix, its candidate units for retrofit investment, its regional power market, and its key planning and financial analysis assumptions—investment hurdle rates and costs of capital, for example. Relevant climate policy and fuel price scenarios are also identified at this stage.

EPRI then customizes the framework to the utility specifications and applies it in a detailed analysis of the scenarios. Annual cash flows from operation of the retrofitted units through 2030 are estimated on the basis of the market analyses, and cash flows are then used to calculate the break-even investment limits for each retrofitted unit and the present values and internal rates of return for alternative investment levels. The result is a clear assessment of comparative and absolute investment worthiness for a range of plausible climate policy and fuel price scenarios, identifying which unit retrofit investments have robust prospects for investment recovery, which are clear losers, and which are on the bubble.

Projects are expected to take four months to complete, with interim results becoming available in the second month. Results will be documented in presentation and table formats, reviewed with the participating utility's technical team, and updated regularly.

For more information, contact Victor Niemeyer, niemeyer@epri.com, 650.855.2744.

Exploring Agricultural Uses for FGD Gypsum

Today more than 75% of the gypsum (hydrated calcium sulfate) produced by flue gas desulfurization (FGD) equipment at coal-fired power plants is sold commercially; wallboard manufacturers are the leading customer base. But stricter clean air standards set by the U.S. Environmental Protection Agency (EPA) are driving generators to add new FGD capacity, which could double or triple gypsum production and saturate the wallboard market. With electric power companies seeking a fresh customer base, EPRI research is focusing on agricultural applications as a largely untapped opportunity for sales growth.

Gypsum mined from geologic deposits is already widely used as a soil amendment to help reduce surface crusting and supply calcium and sulfur for plant nutrition. Widespread acceptance by farmers and regulators for agricultural applications of FGD gypsum will depend on a rigorous examination of its effectiveness and safety. Field experiments are needed to determine appropriate application rates for a variety of soil and crop types and to assess the potential for environmental effects associated with the applications.

Responding to these needs, EPRI has established a national network of test sites where FGD gypsum is being applied to specific crops and soils. Launched in 2006, the test program includes more than a dozen sites in six states—North Dakota, New Mexico, Indiana, Arkansas, Alabama, and Ohio—with new sites expected in two or three more states. All experimental work at the sites is conducted through tailored collaboration projects with individual EPRI member utilities.

Tests and Analysis

Crops being evaluated include wheat, corn, cotton, alfalfa, canola, Bermuda grass pasture, and mixed-grass pasture. Gypsum application rates vary from a high of 10 tons per acre for wheat and alfalfa to a low of only about 54 pounds per acre for canola. Initial crop yields at three sites were somewhat higher for plots treated with gypsum, but larger numbers of test results over multiple growing seasons will be required before definite conclusions can be drawn.

Chemical analyses of FGD gypsum indicated few differences from commercial gypsum products. The commercial gypsum had somewhat higher carbon and nitrogen content, probably resulting from the incorporation of additives to produce an easily applied granular form. Trace levels of mercury were found to be higher in the FGD gypsum but were still very low. Initial soil analyses at two treated plots indicated higher calcium and sulfur content after application of FGD gypsum, but there were no significant differences in the trace metal content of the soils.

In addition to establishing the network of agricultural test sites, EPRI is working with the EPA and the Agricultural Research Service of the U.S. Department of Agriculture, as well as other stakeholders, to aggregate and analyze data and insights from various ongoing research efforts in this area. The aim is to provide a thorough risk assessment of FGD gypsum agricultural uses, which can serve to establish standards for widespread application. A summary of research results to date has been published in the December 2008 EPRI report *Flue Gas Desulfurization Gypsum Agricultural Network* (1015777).

For more information, contact Ken Ladwig, keladwig@epri.com, 262.754.2744.

Tests in a North Dakota canola field indicate that FGD gypsum could help amend sulfur-deficient soil.

Utilities, Automaker, EPRI to Field-Test Plug-in Hybrids

The plug-in hybrid electric vehicles (PHEVs) now on the drawing board promise significant advances over today's hybrids: three times the fuel economy, up to 40 miles of electricity-only operation, and overnight charging from standard wall outlets. With the added flexibility of unlimited gasoline-powered operation for longer trips, the PHEV is expected to be an attractive option for most consumers' regular driving needs.

To ensure that these vehicles are fully and seamlessly integrated into customers' electricity systems, EPRI and Ford Motor Company are conducting a three-year field trial of the prototype Ford Escape PHEV connected to utility systems across North America. "By the time these vehicles become commercialized, automotive and electricity companies will need to have already worked out a great many technical issues, including the charging interface, vehicle-to-grid communication standards, smart charging technologies, and systemwide management of the charging patterns of thousands or even millions of connected vehicles," said Mark Duvall, director of EPRI's Electric Transportation program. "True integration will require that the auto and utility industries work together on infrastructure, creating standard protocols and solving problems before designs and equipment become locked down and difficult to change."

A Broad Field

The test program expands on field trials set up in 2007 under a collaborative partnership of Ford, Southern California Edison, and EPRI. New participants include New York Power Authority, Consolidated Edison, American Electric Power, Southern Company, Progress Energy, DTE Energy, Pepco Holdings, Hydro-Québec, National Grid, and New York State Energy and Research Development Authority. The U.S. Department of Energy has committed $10 million to the project. The wide geographic distribution of the program's 21 test vehicles will enable analysis of regional differences in the effect of PHEVs on the power grid, according to Arshad Mansoor, EPRI vice president for Power Delivery and Utilization. "Bringing the additional utilities on board raises the program to a new level," he said. "We expect the sharing and transfer of data among the new participants will lead to much more robust results." Ford will complete delivery of the test vehicles to the participants by the end of May.

The test cars are based on Ford's successful Escape Hybrid. Each prototype has been fully engineered to integrate an advanced lithium ion battery system produced by Ford partner Johnson Controls–Saft. Unlike PHEVs converted by third parties from conventional hybrids, each test vehicle has been carefully and extensively modified to ensure it meets all of the safety, performance, and reliability requirements of the original stock vehicle. These are the first PHEV passenger vehicles developed by a major automaker as part of the new generation of plug-ins that will be offered in the coming decade. Ford plans to commercialize a plug-in hybrid vehicle by 2012.

Program Focus

The test program focuses on four areas: battery technology, vehicle systems, customer usage, and grid interface/charging infrastructure. Data on charging infrastructure will be particularly important. Many utilities developed their own automated metering infrastructures (AMIs) as part of advanced meter reading, billing, demand response, or smart grid initiatives before PHEV charging emerged as a near-term application. Charging systems will need to include communication and connectivity protocols that can work seamlessly with a variety of utility AMI systems. EPRI is at the forefront of smart charging and interface development and will be working closely with participants' AMI technical experts to ensure effective integration and to resolve compatibility issues.

Project participants will receive all the vehicle data and test results from the entire fleet of test vehicles, as well as reports on each of the project's analytical topics. "The performance and design are impressive, and the car is receiving many compliments," said Mike Ligett, director of market and energy services at Progress Energy. "We look forward to using it in smart charging projects in North Carolina to gain real-world experience of customer behavior and technical performance. PHEVs are likely to become a very big deal in the industry within just a few years, and this allows us to be involved as a development partner rather than just an observer."

For more information, contact Mark Duvall, mduvall@epri.com, 650.855.2591.

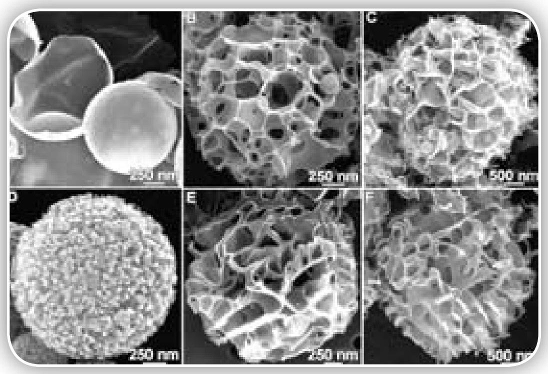
Air to Ground, Gas to Solid: Getting the Mercury out of Emissions While Keeping the Ash in Concrete

More than 20 states have imposed stringent limits on mercury emissions from power plants, and the U.S. Environmental Protection agency is developing its Maximum Achievable Control Technology (MACT) regulations for power plants in response to a 2008 court decision. Some states currently mandate 90% or greater mercury removal from the flue gases of coal-fired power plants, and control technologies will probably have to perform above that standard to meet long-term emission standards. New limits are also being considered on emissions of other trace metals, such as arsenic and selenium, as well as acid gases and organics.

EPRI is working with the electricity industry and its stakeholders to develop and evaluate new, cost-effective mercury controls that will perform well with various power plant configurations, operating conditions, and coal types. Some control technologies are nearing commercial readiness following field testing at various plants. Other technologies are also being developed and tested, particularly if they offer the potential to lower control costs and help preserve the option to use ash in making concrete.

Promising Capture Techniques

For power plants that do not have a selective catalytic reduction system for reduction of nitrogen oxides and a flue gas desulfurization unit for sulfur dioxide capture—or in cases where these controls together do not remove enough mercury—two technologies offer the most promise for mercury reduction: the injection of activated carbon into flue gas or the addition of bromide into the boiler.



Development of new, highly porous carbon structures could greatly increase mercury adsorption.

In the first case, activated carbon is powdered and mixed with the flue gas upstream from a particulate control device, such as a fabric filter or electrostatic precipitator. Mercury adheres to the carbon particles, which then are captured and removed by the particulate control system. Full-scale tests of this technique have been conducted at 40 coal units and show high mercury capture for western coals at reasonable injection rates. Tests at plants using eastern bituminous coals have so far been less successful, largely because the high sulfur content in the flue gas interferes with adsorption of the mercury on the carbon particles.

Adding halogen compounds—particularly bromide salts—to the feed coal before it enters a plant's boiler oxidizes elemental mercury, converting it to a form that is more easily captured by downstream particulate control devices. Full-scale tests of this approach have been conducted at 14 coal units fueled with western coal or lignite, resulting in greater than 90% mercury oxidation. The effectiveness of this technique was enhanced in units that also employ selective catalytic reduction for emissions control. The fate of bromine compounds in power plant flue gas streams and their potential impact on various plant components, however, remain poorly understood, and EPRI is conducting further tests to resolve these uncertainties. The effectiveness of this approach for units fueled with bituminous coal is also uncertain.

Research on Concrete Applications

A major consideration in designing mercury controls is to maintain the option to substitute ash for portland cement in manufacturing concrete, considered the largest beneficial use of fly ash. The presence of activated carbon darkens the concrete and decreases the amount of air that is entrained in it. For most applications, concrete must contain air bubbles so it can expand and contract without cracking in response to temperature changes. Tests to date indicate that modest amounts of activated carbon are acceptable in concrete, although a three- to fourfold increase in the amount of an air-entrainment agent is required. EPRI continues to investigate the acceptable limits for activated carbon in concrete and is evaluating ways to mitigate problems—for example, developing mercury sorbents with less impact on air-entrainment agents or formulating new air-entrainment chemicals that are not affected by carbon.

Meanwhile, other mercury control options are being investigated as lower-cost alternatives for long-term compliance. EPRI has initiated a new program to evaluate the use of sorbent structures—such as plates, honeycombs, and pellets—that could remove mercury when placed in the flue gas stream. The advantage of such fixed structures is that they do not contaminate the fly ash and generate very little waste product. With selection of suitable sorbent materials, the fixed structures could also be used to capture other trace metals.

For more information, contact Ramsay Chang, rchang@epri.com, 650.855.2535.

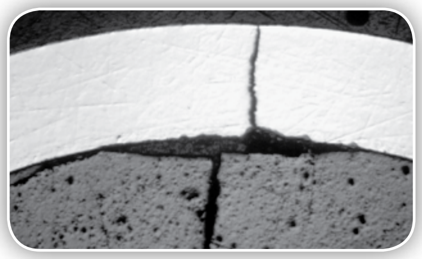
TECHNOLOGY AT WORK

Member applications of EPRI science and technology

Exelon and TVA Use FALCON to Improve Fuel Reliability

Fuel reliability is critical to the safe, economical operation of nuclear power plants. Fuel failures allow radioactive material to leak from the fuel rods into the reactor coolant, affecting plant operations and increasing personnel exposure. Fuel failures have cost the U.S. nuclear industry more than $300 million over the past decade. Through its Fuel Reliability program, EPRI is collaborating with the nuclear industry to eliminate fuel failures by 2010, the target date established in an industry initiative led by the Institute of Nuclear Power Operations.

EPRI developed a fuel performance software program called FALCON to help plant operators evaluate a variety of fuel performance parameters related to operational and hypothetical-accident analyses. Exelon and Tennessee Valley Authority recently used FALCON to analyze their fuel failure vulnerabilities and develop operating strategies to avoid future problems.



Missing pellet surface defects create localized stresses during startup that can lead to cracks in the protective cladding surrounding the fuel pellet.

Modeling Pellet-Cladding Stresses

One fuel failure mechanism is pellet-cladding interaction (PCI), which occurs during or subsequent to a significant power maneuver in the core. PCI failures are initiated by stress corrosion cracking of the zirconium alloy cladding that surrounds the uranium dioxide fuel pellets. Several factors may contribute to stress corrosion cracking, including manufacturing defects and operating variables, such as power ascension rates during startup.

One manufacturing defect that increases the likelihood of stress corrosion cracking is missing pellet surface—imperfections in the geometry of the fuel pellets. As the rod is brought up to power and the fuel pellets heat up and expand, the missing pellet surface can produce non-uniform stresses, causing the fuel cladding to crack. To prevent this outcome, fuel vendors provide startup guidelines to keep cladding stresses at safe levels. Utilities following these guidelines have nonetheless experienced occasional fuel failures.

The FALCON software models the behavior of fuel pellets within fuel rods and also the complex thermal-mechanical interactions of fuel and cladding. FALCON's detailed analyses can help utilities manage power maneuvering by ensuring that stresses don't exceed a threshold that could lead to fuel failures.

Exelon: Analysis at Braidwood and Byron

When Exelon experienced startup and mid-cycle fuel failures at its Braidwood Unit 1 and Unit 2 reactors, the utility sought EPRI's assistance in identifying and mitigating root causes. The Exelon-EPRI team used FALCON to model the Braidwood situation and evaluate 40 scenarios by examining numerous variables that could influence fuel reliability.

The FALCON analysis pointed to PCI as the failure mechanism, possibly aggravated by missing pellet surface. For a more definitive diagnosis, the project team shipped selected fuel rods to the Studsvik hot cell lab in Sweden, where destructive examination confirmed FALCON's diagnosis.

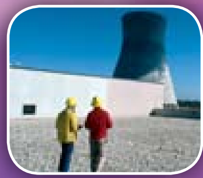
While the hot cell examinations were still in progress, the project team used FALCON to develop startup ramp rate strategies to minimize the risk of future fuel failures. Similar strategies were also applied at Exelon's Byron Unit 2 reactor, which was restarted without fuel failures. This success led to extended changes in operating procedures, according to Bob Tsai, manager of pressurized water reactor fuels at Exelon: "Over the last two years, we have used FALCON to guide power ascension for five startups at Braidwood and Byron, each of which was performed successfully and without any fuel issues."

TVA: Failure Avoidance at Watts Bar

At TVA, fuel rod leakage was detected on successive cycle startups at the Watts Bar nuclear plant despite startup ramp rates that were more conservative than fuel vendor guidelines. Since the Watts Bar fuel was fabricated by the same process as the Braidwood fuel—and thus was known to contain missing pellet surface defects—it was considered likely that a similar condition was affecting Watts Bar.

To avoid PCI fuel failures on the next cycle startup, TVA and EPRI used FALCON to analyze the impact on cladding stress. The analysis determined that the leakage could have resulted from missing pellet surface defects in high-power assemblies. The team then used FALCON to develop ramp rates that would provide protection during startup. With these ramp rates, the cycle startup was completed with no fuel leakage, and the optimized ramp-up margins were employed successfully until the fuel that was assumed to be impaired by missing pellet surface was discharged from the reactor.

For more information, contact Suresh Yagnik, syagnik@epri.com, 650.855.2971.

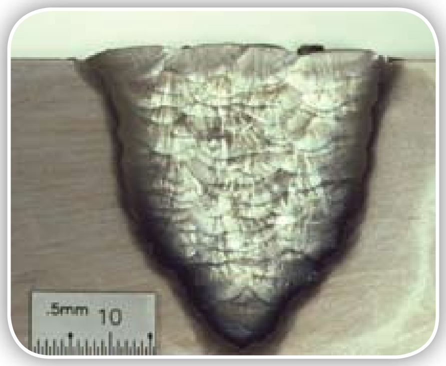

Improved Filler Metal Strengthens Welds

EPRI has developed and sponsored the commercialization of a new product that will address a key issue in dissimilar metal welds in retrofit and new power plant boilers.

Boiler tubing is made of different types of steel. Superheater and reheater sections, which operate at high temperatures, require components manufactured from austenitic stainless steel, which provides increased creep strength and corrosion resistance. Tubing in the earlier boiler stages, where temperatures are lower, can be made of less-costly ferritic alloys, such as Grade 22 steel. Historically, dissimilar metal welds joining austenitic and ferric sections have been subject to premature failure. This issue has gained importance in new plants designed for higher efficiency that use such advanced alloys as the higher-strength ferritic/martensitic Grade 91 alloy, developed for higher temperatures and pressures.

Better Filler Composition

Research has shown that a number of issues associated with dissimilar metal weld failures relate to the composition of the filler metal added to the joint during welding. EPRI's Fossil Materials and Repair program developed a new nickel-based filler, called EPRI P87, that avoids many of the problems that have caused conventional filler materials to fail prematurely.



For example, one key weld failure mechanism involves carbon migration, where carbon diffuses from the low-alloy base metal to the higher-alloy filler metal, resulting in a weak zone in the ferritic base metals; when failure occurs, it is invariably in this weakened region. "Carbon has an affinity for chrome and will migrate from a lower-chromium alloy to a higher one," said Kent Coleman, senior project manager for materials and chemistry at EPRI. "Because it contains less chromium, the EPRI P87 filler minimizes or eliminates carbon migration." Compared with conventional filler metals, EPRI P87 also has a coefficient of thermal expansion that is closer to that of the ferritic steels (Grade 22, Grade 91, and Grade 92 steels). This means that, as tubing expands with heating, there is less difference in expansion between the filler and the base metals, resulting in less stress on the weld.

In addition, EPRI P87 offers advantages related to post-weld heat treatment, a standard tempering procedure used to toughen the weld metal. Current construction codes require post-weld heat treatment at different temperatures for the hardenable ferritic materials, Grade 22 and Grade 91/92 steels. When different steels are joined, the treatment must be performed at the higher temperature. But if lower-alloyed materials are overheated, degradation can occur.

EPRI research shows that before the final joint is made, P87 can be used to "butter" the base metals—add metal to the end of the tube, providing a protective buffer that allows treatment of each alloy at the optimal temperature. If this procedure is followed, the final weld may be made without post-weld heat treatment. The EPRI filler metal also allows the separate treatments to be done at the factory on many components at a time, rather than joint-by-joint at the plant site. This can significantly reduce the time allotted for post-weld heat treatment in the construction schedule.

Further Developments

Metrode Products Ltd. has commercialized EPRI P87 and has sold about 1500 pounds of the filler metal in stick welding form to Babcock and Wilcox (B&W) for construction of American Electric Power's 600-megawatt Turk Plant in Arkansas—the first ultra-supercritical pulverized coal plant in the United States. B&W believed EPRI P87 to be the only filler that could accommodate the unit's firing conditions. Said B&W's John Hainsworth, "The P87 filler metal allowed us to increase our temperature use limits for the dissimilar metal welds between the Grade 91/92 alloys and the austenitic stainless steels above the roof line."

EPRI's Fossil Materials and Repair program and B&W are working to develop solid wire for other welding processes, which will allow for more flexibility and increased use of the filler.

For more information, contact Kent Coleman, kcoleman@epri.com, 704.595.2082.

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 look under My Research Areas.

Feasibility of Manufacturing Out-of-Service Western Utility Poles (1015560)

When transmission and distribution poles are removed from service, utilities must decide if the out-of-service poles can be reused for manufacturing purposes or whether they will be disposed of in landfills. This research involved acquiring out-of-service poles from utilities in Oregon, sawing and splitting them, and determining if there was a market for the resulting lumber, split posts, and rails. The study demonstrated that high-quality wood products can be produced from out-of-service poles, but that the market for these products needs to be further developed to make this an economically viable opportunity for utilities.

Commercial Building Energy Efficiency and Efficient Technologies Guidebook (1016112)

Commercial buildings account for 18% of all energy use in the United States and about 27% of energy use in buildings. This guidebook provides basic information on how commercial buildings use energy today and suggests opportunities for improving electric energy efficiency. The guidebook is designed to help utility staff assist their customers in better understanding what the commercial sector really looks like, how it uses electricity today, and what the opportunities are for improving energy efficiency and reducing greenhouse gas emissions. The report presents typical demand profiles of commercial buildings in several geographic regions of the United States and identifies end-use loads and time periods that can be addressed to improve overall efficiency in commercial buildings. A version that can be shared with the utility customer will be published soon.

Digital Instrumentation and Control Operating Experience Lessons Learned (1016722)

This report presents five case studies that highlight lessons learned from over 20 years of operating experience with digital instrumentation and control (I&C) systems in nuclear plants. The case studies—fictional composites of actual events—describe key I&C system mishaps and provide guidance on how utility engineers can avoid similar problems in the future. Targeted for engineers, technicians, project managers, and line managers, and designed to complement existing training programs, the studies are presented in an interactive multimedia format to create an efficient technical transfer mechanism that personnel can use at their convenience.

Characteristics of Natural Gas Trading and Exchanges (1016790)

Natural gas accounts for 54% of annual electric utility fuel expenses, and its cost frequently drives power prices. The recent boom in natural gas trading and the controversies surrounding it have brought new attention to the importance of the market for utilities. This report describes market fundamentals and addresses the latest trends and changes taking place in the principal natural gas trading venues, the actions being taken to strengthen regulatory oversight, and the implications of all these changes for electric utilities. The report offers an integrated view of the market and helps to demystify its increasing complexity. The report's findings will help utilities identify optimal strategies for procurement planning and reducing fuel costs.

BPWORKS™ 1.0: EPRI Risk Ranking of Buried Piping Systems, Version 1.0 (1018150)

Inspecting the thousands of segments of buried pipe at a typical nuclear plant can be difficult and expensive, and a systematic method for prioritizing such inspections is needed. The EPRI BPWORKS™ software application is designed to help plant owners rank piping segments according to the risk of degradation initiating on the inside (flow side) of the pipe, on the outside (soil side), or on both sides in combination. The ranking is done by analyzing the likelihood of a leak or break in each piping segment and determining the consequences if that breach were to occur. The likelihood and consequence information is then used in a risk matrix to help prioritize inspections.
Platform requirements: Windows Vista / XP SP2 / 2000 SP4.

Program on Technology Innovation: Integrated Generation Technology Options (1018329)

With an aging infrastructure and a changing regulatory environment, energy companies and other stakeholders need credible and consistent information on conventional and emerging electricity technologies. This report, available in the public domain, provides an objective, up-to-date overview of the eight central-station generation technologies likely to dominate the U.S. generation mix in the coming decades. Based on EPRI's industry-standard *Technical Assessment Guide (TAG®)*, the report presents the technical status, performance, costs, and markets for these technologies, with assumptions and uncertainties clearly delineated. Utilities will find this information valuable in their planning processes and in interactions with stakeholders, regulators, and public advisory groups.

WIRED IN

Perspectives on electricity

AEP's Ambitious Technology Agenda

"Economic downturn notwithstanding," this U.S. utility is leading advances in generation, transmission, efficiency, and customer satisfaction.

Michael G. Morris
Chairman, President, and Chief Executive Officer,
American Electric Power

Imagine a world where electricity is assured, where advanced technologies enable power plants to run more cleanly and help consumers use energy more efficiently, where nations come together to address climate change, and where communities prosper and grow.

At American Electric Power, we are not just imagining this world, we are working toward it. And new technologies developed through research and development will play a vital role.

Coal is our nation's most abundant fuel and will remain our "workhorse" fuel for decades to come. In 2009, we plan to begin operation of a 20-megawatt validation project for carbon capture and storage technology at our Mountaineer Plant in West Virginia. We are seeking funding from the U. S. Department of Energy to build a commercial-scale version of this technology at the same facility. Once Congress enacts a cap-and-trade program for carbon emissions, the ability to capture and permanently store carbon will be paramount for a company like ours, which produces most of its generation from coal.

We are working to bring advanced coal technologies—including ultra-supercritical pulverized-coal and integrated gasification combined cycle (IGCC) systems—into commercial operation. We have received the necessary approvals to begin construction of our Turk Plant in Arkansas, the first ultra-supercritical plant in the United States. However, our plans to build IGCC plants in Ohio and West Virginia have stalled because of legal challenges in Ohio and opposition from the Virginia State Corporation Commission. We remain convinced of the importance of constructing these two plants, although the urgency of the need for new baseload capacity has been lessened by the economic downturn.

Electricity production is only part of the equation, however. We support the development of an interstate extra-high-voltage transmission system, regulated at the federal level. We call this concept Interstate 765, because it would be the electrical equivalent of the interstate highway system. Such a system would eliminate bottlenecks, increase energy efficiency, enable more renewable energy to be brought to market, foster greater competition, and improve the reliability of the transmission grid. We are involved in a number of partnerships to construct new 765-kV transmission facilities, such as our joint venture with Allegheny Energy to build the Potomac-Appalachian Transmission Highline, or PATH.

We have also started work toward an enhanced electric distribution system that will give our customers far more control and choice over their electricity usage. This advanced system, part of our gridSMART℠ initiative, will improve service reliability and increase energy efficiency. Our agreement with General Electric Company to deploy technology and equipment is an important element of the plan, which will provide our 5.2 million customers with "smart" meters by 2015. The gridSMART enhancements include distribution automation capabilities that will, among other things, greatly speed the process of outage restoration and eliminate the need for some human intervention.

The gridSMART initiative also involves technology development in the areas of fuel cells, large-scale batteries, and other energy technologies. We are pleased to be a leader in the deployment of sodium sulfur (NAS) batteries, which can be implemented to support local circuits and take the strain off substations nearing load capacity. These batteries can support megawatt-sized loads for hours in the event of an outage. We have installed 7 megawatts of NAS batteries and are planning additional deployments in the future.

Another technology with significant potential to reshape our business is the plug-in hybrid electric vehicle (PHEV). AEP is one of 11 electric utility companies and research organizations currently working with Ford Motor Company and EPRI to conduct real-world tests on Ford Escape PHEVs. These tests are providing data in the areas of battery technology, vehicle systems, and customer usage.

The economic downturn notwithstanding, we feel the investments we are making in transmission infrastructure, advanced coal technologies, energy efficiency, and customer control are absolutely essential. Working with others, we have the talent and dedication to provide power for today while preparing for the needs of tomorrow.

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