SUMMER 2006

EPRI JOURNAL

ELECTRIC POWER RESEARCH INSTITUTE

ENERGY EFFICIENCY

ALSO IN THIS ISSUE:

Climate Policy

Generation Under Carbon Constraints

ELECTRIC POWER
RESEARCH INSTITUTE

The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California, and Charlotte, North Carolina, was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together members, participants, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of electricity generation, delivery, and use, including health, safety, and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents nearly 15% of EPRI's total research, development, and demonstration program.

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EDITORIAL

COVER STORY

Electric utilities and policymakers alike are taking a new look at energy efficiency as a least-cost solution to the challenge of reducing carbon emissions. And with the development of advanced sensors and communications technology, an era of interactive, two-way learning is emerging that can augment and reinforce traditional forms of energy efficiency.

FEATURES

The issue of controlling CO_2 emissions is now working its way into state and local decision-making processes, and a number of market-based initiatives are already gaining traction.

With high fuel costs and uncertainties about future CO_2 regulations, prudent power providers are likely to invest in a balanced portfolio of advanced low- and non-carbon-emitting technologies.

DEPARTMENTS AND LISTINGS

Editorial

CO_2 Emissions: Solutions on Both Sides of the Meter

As scientific evidence mounts that human activities are contributing to climate change, the prospect of more-widespread constraints on greenhouse gas emissions is becoming increasingly likely. The electric power industry continues to be very active in pursuing solutions to the CO_2 emissions challenge. As a result, the development of new clean-coal technologies, advanced nuclear plants, and more-cost-competitive renewables is on track to make a robust portfolio of clean, more-climate-friendly generation options available by 2020. Electricity may also be able to help reduce CO_2 emissions in the transportation sector—which accounts for a third of U.S. emissions—if electric, plug-in hybrid, or hydrogen-fueled automobiles find commercial success.

Work on clean energy supply—outlined later in this issue—has been impressive, but the possibilities on the customer side of the meter are equally compelling. The equation is simple: more-efficient use of electricity reduces the amount of electricity needed, which reduces the amount of power and emission by-products produced. Energy efficiency represents a largely unappreciated and underutilized opportunity, considering that estimates of possible reductions range from 10% to 25% of total U.S. energy consumption. Even if we consider only the lower end of these estimates, the potential is huge. With high fuel prices and the prospect of large new investments in advanced generation units on the horizon, it makes strategic sense to harvest the economies and benefits that efficiency can provide.

A fresh look at energy efficiency makes it clear that we've just scratched the surface in tapping this resource. In the 1970s, efficiency and conservation efforts stressed customer restraint: turn it down, turn it off, just do with less. Today we really can use less to do more, largely as a result of national appliance efficiency standards, new building codes, and strong market forces that favor both efficiency and size reduction in the development of new end-use equipment.

The possibilities for the future are even more exciting, thanks to innovations in digital technology and interconnectivity. Smart end-use appliances will be capable of managing their own operation and energy requirements, responding to real-time and day-ahead hourly price signals delivered from the energy provider via two-way communications links that run through advanced meters. This dynamic prices-to-devices℠ capability—coupled with complementary innovations in regulation and markets—will enable a systemwide optimization characterized by more-efficient generation dispatch and more-efficient end use of electricity.

Such technical advances also promise to change the relationship between the industry and its customers, allowing ratepayers to become involved in a more meaningful way. Consumers will be able to set their networked, smart home appliances for personal preferences of comfort, convenience, and energy cost, and the devices themselves will then take action automatically to match their operations to these variables. In addition, working through the two-way communications link with their service provider, ratepayers can help design their own service packages, choosing the rate and service options that best match their needs and values. Such interactive, dynamic systems will allow efficient energy use to become another integrated function in an increasingly personalized, networked digital society.

Electricity is a wonderful thing because it can be produced in so many different ways and because it is clean and convenient at its point of use. These characteristics make an increased use of electricity integral to virtually all of tomorrow's energy scenarios. In light of this increasingly electrified future, it is imperative that we accelerate development and deployment of both advanced generation technologies and advanced efficiency infrastructures. It is not an either/or proposition—we must do both. A proactive stance by the electric power industry that embraces both generation and efficiency technologies is essential to meeting the challenges of a carbon-constrained future.

Steven Specker
President and Chief Executive Officer

Contributors

Climate change and the challenge of controlling global carbon emissions are issues that affect virtually every aspect of the electricity enterprise, from all types of power generation technology to end-use efficiency to regulation to power markets. As a result, the stories in this issue of the *Journal* reflect the work and expertise of a great many EPRI staff members. Prominent among those whose help and perspective shaped these articles are Steve Gehl, Tom Wilson, Brent Barker, Clark Gellings, and Ellen Petrill.

Steve Gehl, technical executive for EPRI's Energy Technology Assessment Center, previously served as director of strategic technology. He came to the Institute in 1982 from Argonne National Laboratory, where he was a staff metallurgist. Gehl received a bachelor's degree in metallurgical engineering from the University of Notre Dame and a PhD in materials science and engineering from the University of Florida.

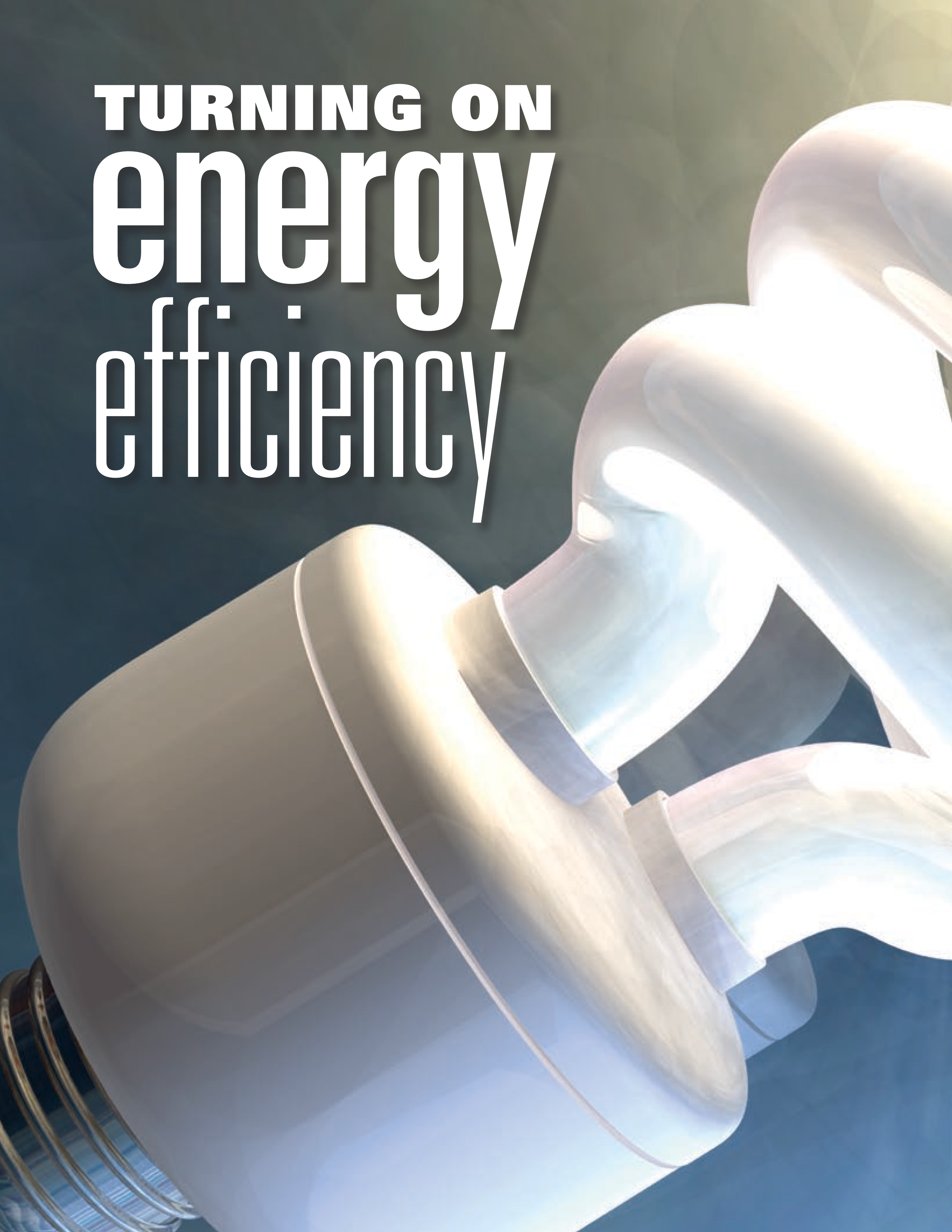
Tom Wilson, manager of EPRI's Greenhouse Gas Reduction Program, came to the Institute in 1985 from an energy-environment consulting practice at ICF, Inc. For the past 18 years, he has led EPRI's research efforts to examine the potential impacts of climate change, climate and technology policy choices, possible emissions reduction investments, and corporate strategies. Wilson received a BS degree in Mathematical Sciences from the University of North Carolina at Chapel Hill and MS and PhD degrees in Operations Research from Stanford University.

Brent Barker, executive director of corporate communications, joined EPRI in 1977 as the editor of the *EPRI Journal.* Previously, he worked at SRI International as an industrial economist and staff author, forecasting the futures of new industries and technologies, and as a commercial research analyst at USX Corporation. Barker holds a BES in mechanical engineering from Johns Hopkins University and an MBA from the University of Pittsburgh.

Clark W. Gellings, vice president, Innovation, began his career at EPRI in 1982 after spending 14 years with Public Service Electric and Gas Company. He has a BS in electrical engineering from Newark College of Engineering, an MS in mechanical engineering from the New Jersey Institute of Technology, and an MS in management science from the Wesley J. Howe School of Technology Management at Stevens Institute of Technology.

Ellen Petrill, director of public/private partnerships, came to EPRI as a project manager in power generation performance and technology and later served in Member Services as director of the western region team. Before joining the Institute in 1984, she worked in R&D at Acurex Corp. and TRW developing and testing advanced combustion systems. Petrill holds BS and MS degrees in mechanical engineering from Stanford University.

TURNING ON energy efficiency



The Story in Brief

Today, in the face of rising fuel costs and increasing concerns about carbon emissions, electric utilities and policymakers alike are taking a new look at energy efficiency as a least-cost solution. And with the development of advanced sensors and communications technology, an era of interactive, two-way learning is emerging that can augment and reinforce traditional forms of energy efficiency. Four building blocks lie at the heart of future progress—advances in communications, smart end-use devices, regulation, and markets.

Imagine walking into an empty room that can adapt to your presence. It has learned your preferences for lighting, temperature, ventilation, and humidity, and it starts reconditioning the space for you in the context of the energy efficiency guidelines for the building, the ambient weather conditions outside, and the marketplace for electricity. Walls and windows are embedded with microscopic sensors, and every individual device and appliance in the room has an embedded microchip with an Internet Protocol (IP) address that receives direct pricing signals from the local electricity provider. Prices move up and the fan slows down or the air conditioning takes a pause. The sun breaks through the clouds and the window glass tints. The room seems a bit stuffy, you simply say so and it responds with a little more fresh air. This type of networked intelligence is all part of the coming "third wave" of end-use energy management that EPRI labels *dynamic systems.* It rests on the emergence of a smart energy controls infrastructure that should be here, at least in cutting-edge commercial design, before 2015. In principle and in terms of the technical potential, it is already here.

The first wave, *energy efficiency,* includes evolutionary efficiency improvements that result naturally from economic factors in free markets. As computers have become smaller and faster, for example, their energy requirements have gone down. This kind of efficiency improvement is pervasive throughout the economy and is part of the relentless drive by organizations, industry, and businesses of all types to improve productivity, to accomplish more with less. The efficiency advantage is physically built into the evolving end-use equipment or process itself, requiring no special action on the part of the user to save energy. Knowledgeable professionals in the field believe that such evolutionary improvements will continue to reduce the growth in electricity demand in the United States by as much as 1% a year.

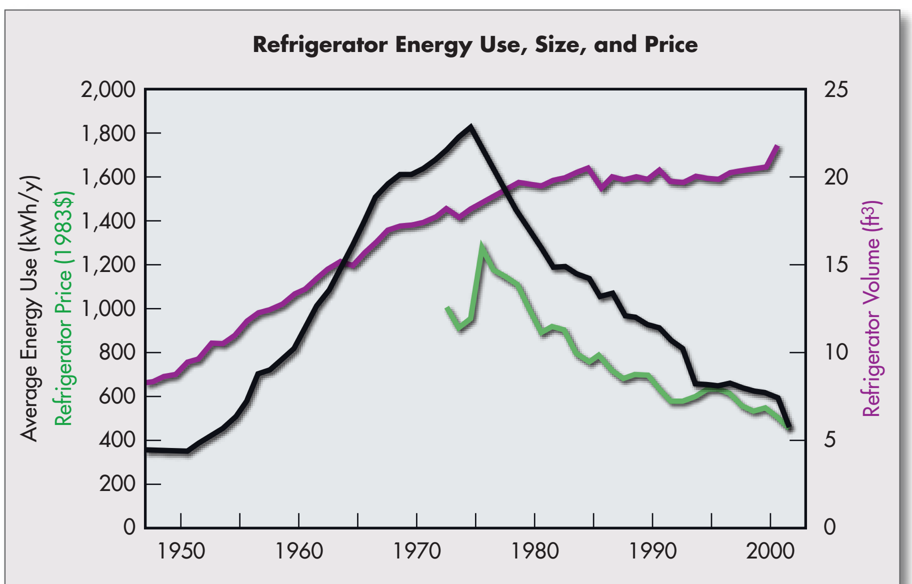
Built-in efficiency gains were given a strong governmental boost during the energy crises of the 1970s, when energy efficiency became a focal point of policy and regulation. Appliance standards, building codes, and utility demand-side management programs introduced a wave of prescriptive measures to augment and accelerate evolutionary improvements. Standards were set and programs were launched, some—such as EPA's ENERGY STAR® program—having large and lasting impact. One of the most dramatic success stories is the refrigerator. As a direct result of federal efficiency standards, refrigerators today use only one-third the electricity consumed by their predecessors of the 1970s, even though unit size continues to increase. Interestingly, the unit price has declined as sharply as energy consumption.

The legacy of these diverse efforts has been to encourage the adoption of more-efficient appliances, the progressive tightening of building codes, and the evolution of HVAC (heating, ventilating, and air conditioning) designs and energy management systems. According to recent studies, the potential energy savings from energy efficiency programs could amount to 5–10% of total U.S. electricity consumption. These savings would be in addition to the evolutionary improvements.

The combined advantage of evolutionary and programmatic changes—ranging from the use of more insulation to the development of better compressors—provides a permanent reduction in energy demand. This benefits customers and society by reducing emissions as well as by reducing or deferring the need for new generation and transmission and distribution (T&D) investments.

The second wave, *demand response,* also began in the 1970s. In this case, the efficiency savings are not built into the end-use appliance or facility but rather are a response function—generally under the control of the customer—that alters the pattern of energy use. Typically, the purpose is to shift demand away from the daily or seasonal peaks, providing some relief to utilities when supplies are tight and costs are high. According to a variety of studies, the potential savings are in the range of 10–20% of peak load.

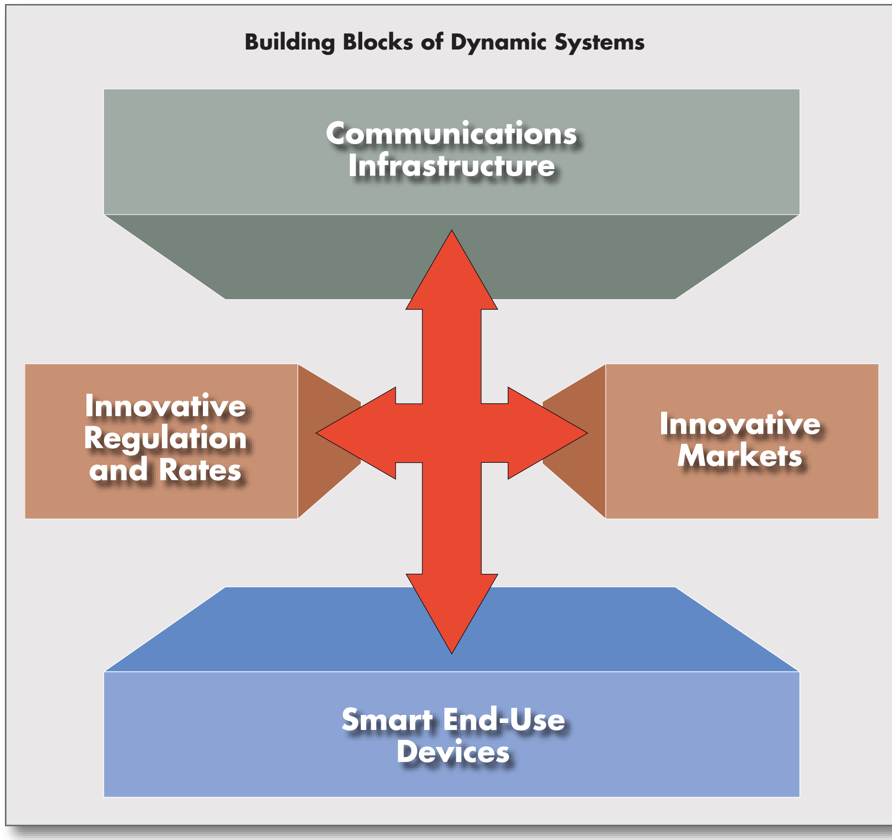
Demand response programs have mostly involved industrial and large commercial customers, whose buildings are controlled



Electricity consumption by refrigerators grew in lockstep with increasing size until energy efficiency standards were instituted in the 1970s. While size has continued to increase, today's refrigerators use less than one-third the energy of their 1970s predecessors, and refrigerator prices have also fallen. (Source: Lawrence Berkeley Laboratories) by sophisticated energy management systems that can work with pricing signals from the local service provider. In certain load reduction programs, the industrial or commercial customer may respond to a notification (by phone, e-mail, or fax) from the utility to reduce load. Programs for residential customers have generally been limited to time-of-day rates, which encourage the shifting of loads to off-peak times, or control by radio or power line carrier signal to curtail or cycle larger loads such as air conditioning compressors.

The third wave, *dynamic systems,* exemplified by the adaptive room scenario, adds intelligence and automated response to the processes and end-use equipment, allowing increased functionality without a rise in electricity demand. Dynamic systems use some of the tools developed for conventional demand response programs, along with advances in communications and emerging smart end-use technologies. This third wave again frees the end user from the need to take action; after the system is set up and general preferences are specified, the appliances themselves make the decisions and even "learn" how to best accomplish efficiency and comfort objectives.

The opportunities of these three waves working together could be substantial, not only to reduce electricity demand and usage, but to address the great societal concerns of the future, such as climate change. According to Steven Specker, EPRI's president and chief executive officer, "The convergence of advanced technologies and communications—including next-generation meters, intelligent end-use devices, and advanced communications infrastructures—offers tremendous opportunities to promote innovative regulation, rates, and markets and to turn load management to the problem of reducing CO_2 emissions." The climate change issue has become one of the key driving forces in the industry today and has brought a new sense of urgency to energy efficiency. Many see energy efficiency as pivotal to reaching global CO_2 emissions targets (see sidebar, "Reducing CO_2 Emissions," on page 9).



Four building blocks are needed to create the smart energy control system that can unleash the next wave of efficiency potential. Innovative rates and regulation will allow pricing structures that encourage efficiency "products" to be incorporated into new market offerings. Smart end-use devices will receive pricing signals directly from power suppliers through an integrated communications infrastructure and will make their own operational decisions on the basis of preset cost, efficiency, and comfort variables.

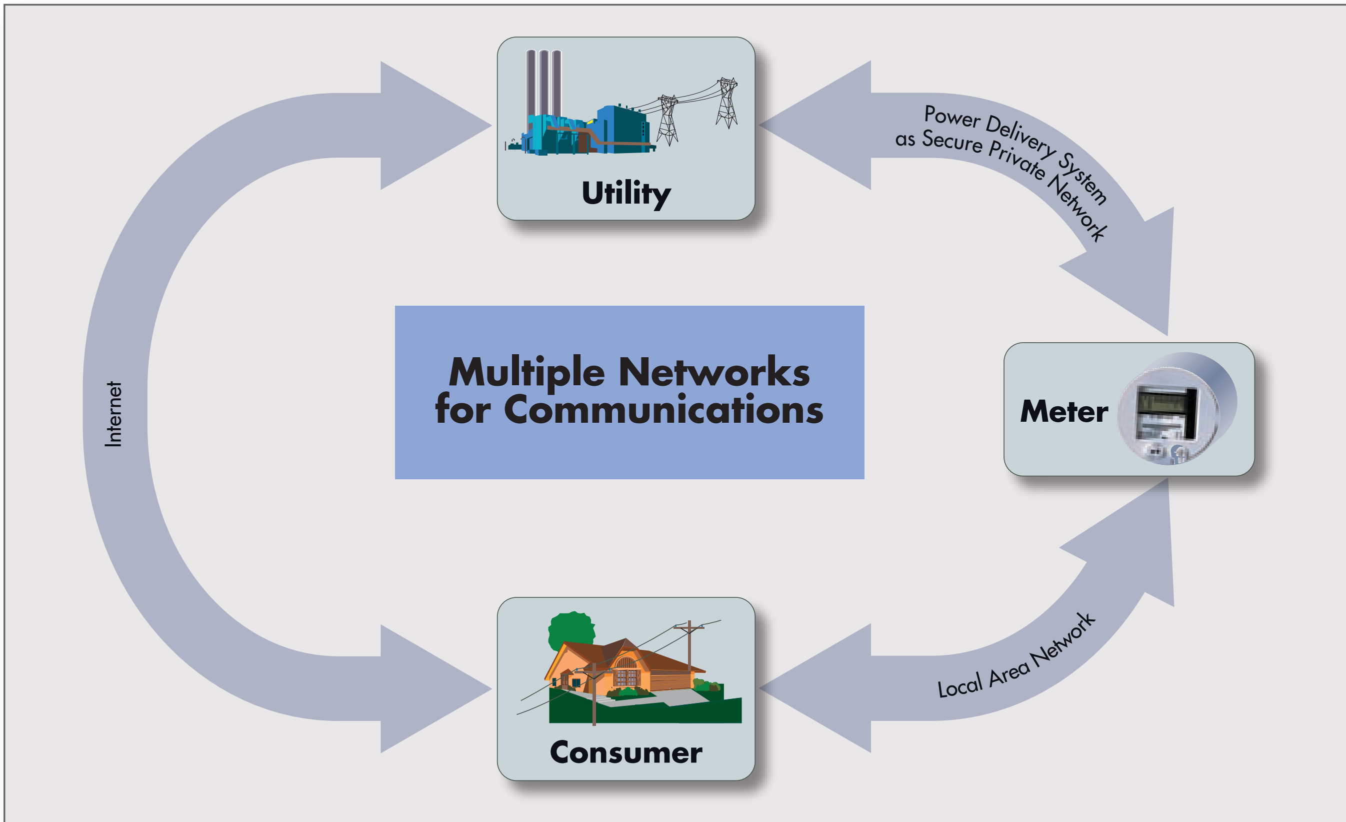
Four Building Blocks

EPRI sees four building blocks necessary to create and support the smart energy controls infrastructure of the future: a communications infrastructure, smart end-use devices and processes, innovative rates and regulation, and innovative markets.

Communications

An advanced communications network will add new functionality to the electricity system that will allow electricity providers to exploit the new technical capabilities in society, ranging from smart appliances in the home to high-tech industrial processes. To tap these capabilities, market information would be exchanged directly with smart end-use devices. This prices-to-devices℠ approach would allow the appliance or equipment to manage its own operation to meet predetermined cost or performance targets. Such a network could also enable devices within a home or business to interact with each other to increase overall consumer benefit.

One linchpin technology in this concept will be the meter. Intelligent meters, working with standardized communications protocols and consumer equipment such as televisions or home computers, can create a two-way information portal through which customers and service providers will interact directly. According to Joseph Hughes, project manager in EPRI's Power Delivery Science and Technology Development Division, "Intelligent meters offer utilities real-time data and applications to serve a wide range of business



Multiple two-way networks can be used for communications between customers and utilities, depending upon the specific need. Standardized wide-area communications links—such as the Internet—are best used for basic information exchange, where privacy and security are not important. Control functions and connections to the power grid will require secure networks.

operations, including transmission, bulk power management, and distributed energy resource integration. They provide intelligence for outage crew dispatch, voltage and reactive power management, power quality monitoring, and advanced asset management functions. They support real-time pricing, billing, change of service, and outage communications. And they enable utilities to offer innovative services such as consumer equipment management, diagnostics, and repair."

A number of U.S. utilities have conducted trials of limited numbers of smart meters and associated communications, but the lack of investment return is a notable stumbling block. With the average profit from a residential customer amounting to around $35/year, it is difficult for any investor-owned utility to justify the installation of a $300 smart meter unless it can be used to facilitate multiple revenue-generating or cost-saving applications. In Europe, ENEL has accomplished one of the most ambitious and significant deployments of such communications-enabled meters in Italy, where over 27 million meters have been installed. Currently, the primary functions used are transmission of consumption data back to the utility and automatic reading of time-of-use rates by the meter. Similarly, Electricité de France is considering installation of 34 million new meters. Other European utilities have installed several hundred thousand of the advanced devices.

Communications protocols for utility-customer links are typically incorporated in signals transmitted through the power line, or wirelessly to an Internet access point (similar to a wireless computer network in a home). Open standards–based communications connectivity is expected to eventually enable the integration of intelligent end-use equipment. A number of options are under consideration for providing new levels of communication between utilities, customers, and intelligent energy systems and appliances. The Internet is a possibility, but at present, it can deal only with information, not with controls. Other options include an advanced Internet with secure protocols, broadband over power lines (BPL), cable, fiber optics, and wireless. In addition, an open standards–based common language will one day enable equipment to "talk," ushering in a level of equipment integration not possible today.

According to Specker, a key to success will be creation of the anticipated open standards–based communications system that will allow all vendors to participate: "The physical communications network can embrace a variety of options. As a strategy, we need to stay flexible and keep the door open for all types of communications that offer appropriate levels of security and protection. Right now the system is still evolving." EPRI is supporting both the vision and the development of the open standards needed to integrate equipment across the industry.

Smart End-Use Devices and Processes

Through advances in distributed intelligence, end-use technologies are beginning to evolve from static devices to devices with a much greater dynamic range. Many appliances that are being manufactured today contain microchips that have IP addresses, meaning they are potentially accessible through the Internet or some other network and can therefore interact directly with suppliers.

One example of equipment that is being upgraded for dynamic performance is the ubiquitous fluorescent light. Southern California Edison has proposed a pilot program that will use utility-controlled, dimmable, energy-efficient T-5 fluorescent lighting as a retrofit for existing T-12 lamps in commercial, educational, and industrial facilities. SCE will be able to dispatch these lighting systems using wireless technology and hopes to reduce lighting load at those facilities by as much as 50%.

The efficiency of a residential air conditioning system or a commercial HVAC system could also be made more dynamic. Embedded software and hardware in the system could optimize operation to minimize consumer energy costs through the use of Internet-accessed hourly electricity prices and day-ahead weather forecasts, coupled with learned patterns of building cool-down and heat-up rates, occupant habits, outside temperatures, and seasonal variables. In practice, these capabilities might play out in the following way: The air conditioning system in a building reads tomorrow's weather forecast—a hot day is coming, and electricity prices are going to be high during the hottest part of the day. The customer has already set acceptable temperature ranges or perhaps a cost limit to drive the air conditioner. The air conditioner has already learned, through neural networks, that it can make the house comfortable at a reasonable cost in such a situation by precooling in the morning when prices are low and reducing load during the peak period when prices are high. And it does so automatically.

Other innovative approaches could further promote the energy efficiency of appliances. The sale of electricity could actually be bundled with specially designed consumer devices—a new refrigerator, for example, could be sold with five years of electricity included in the purchase price. Because the device is designed to meet specific energy efficiency goals and has the capability to self-monitor and -meter, it has the means to optimize performance at a specified level of energy consumption. Of course, setting up such an offering would require regulatory flexibility and markets that permit the recovery of investments in efficiency and demand response.

Reducing CO_2 Emissions—The Driving Force Behind Efficiency

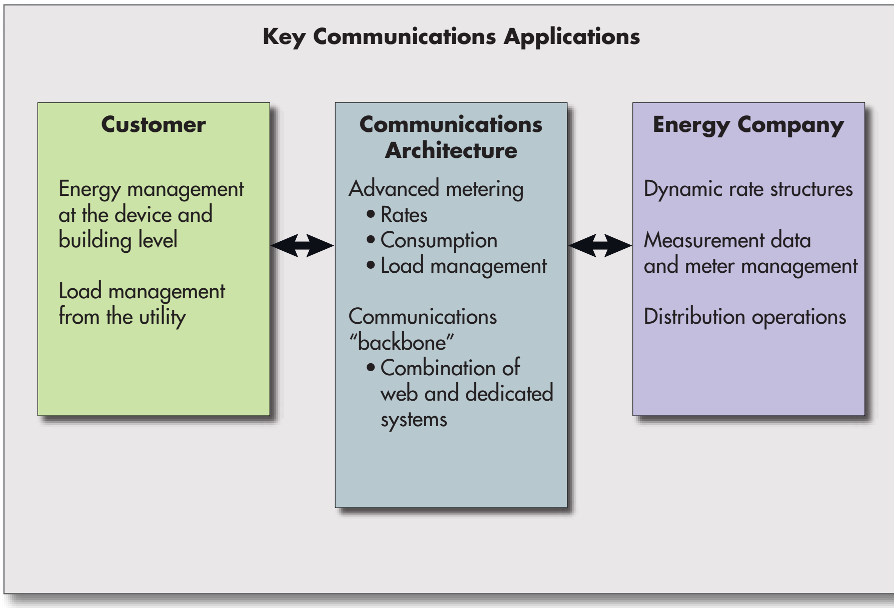
The 800-pound gorilla now driving long-term global energy policy—and by extension the long-term expansion planning of electricity suppliers—is climate change. Expectations are growing for the so-called efficiency option to assume a leading role in addressing CO_2 reduction, a role equal in scale to that of the major electricity supply options.

Efficiency policy goals will likely put a double burden on the electricity industry, since all large-scale efforts to move the nation toward cleaner energy will mean shifting more of the CO_2 burden to electricity producers. The reason is that electricity is the only practical means to deliver clean energy on a large scale—regardless of whether it is derived from nuclear, renewable, or fossil sources. The shift in the clean-up burden could accelerate sharply if the transportation sector moves headlong toward electricity in the next three decades through the introduction of plug-in hybrids and comparable vehicles.

The scale of the task is enormous. If climate policy is to achieve the current internationally agreed-upon goal of stabilization of concentrations of greenhouse gases in the atmosphere, a near-complete transformation of the energy system will ultimately be required—from a global energy system that is 85% CO_2-emitting today to one that is predominantly non-emitting. This will not be possible without substantial contributions through energy efficiency.

Climate policy could change the comparative economics of supply-side and demand-side options in the years ahead. Since climate policy will likely increase the cost of energy, the economic attractiveness of individual end-use energy efficiency investments will grow. Natural gas–fired generation sets the price of electricity in many regions. An $11/metric ton value assigned to CO_2 emissions could increase the cost of natural gas peaking equipment by $5–$7/MWh, likely creating substantial pressure to increase wholesale and retail electricity prices and to reevaluate efficiency options.

From a utility perspective, energy efficiency may be the low-hanging fruit in the search for ways to reduce carbon emissions. "It's going to be a lot less expensive than either renewables or the capture and sequestration of carbon," states Richard Hayslip, assistant general manager at Salt River Project. "We ought to take advantage of our opportunities for energy efficiency before moving on to the more expensive strategies."



Effective, dynamic efficiency management will require seamless information exchange between customers and their energy company. The communications architecture bridging these entities will require advanced metering to transmit rates and price signals, consumption patterns, and load management decisions.

The concept of automated interactive communication and control is extremely powerful, and many believe that networked intelligence will eventually come to dominate daily life. Cisco CEO John Chambers has a grand vision of the home in the twenty-first century that is based on a highly networked "digital lifestyle." Major hardware and software suppliers such as Intel and Microsoft now envision that every consumer device that can be networked will be networked. Consumers will use these interconnected appliances in the home for entertainment, convenience, health care, and energy management. Building control systems will use networked appliances for lighting, comfort, and energy management.

Standards are already under development to make sure that products will be able to network effectively in the future. The open architectures that enable interoperability now appear to enjoy wide acceptance, although it has taken years to achieve. Virginia Williams, director of engineering and standards for the Consumer Electronics Association, says it was market pull that forced the change: "Our own members…want a proprietary network. But people don't buy networks; they buy components, and they expect to be able to mix and match them, and they want competition on any given product. So the idea of a single-brand network…set back the industry maybe a decade."

With the home and commercial network in place to meet consumer demands for entertainment, comfort, and energy management, the capability to receive electricity price signals and manage device operations in response will be just another added functionality. Consumers will be able to select their energy management scheme and allow it to operate automatically—for example, to meet a desired comfort level at the minimum cost. Eventually, all electronic devices will have these capabilities, and the energy efficiency advantages will be inherent in the devices and the networks.

Innovative Rates and Regulation

Innovative ratemaking will be critical for ensuring a re-emergence of efficiency incentives. In the days before utility restructuring, state regulatory agencies set the prices that utilities could charge to make a reasonable profit. Such pricing structures folded energy efficiency into the mix as a societal good. Today, however, unless regulators create new incentives, efficiency has to stand on its own economic merits.

In all states except California and Hawaii, utilities are now, in effect, rewarded for selling energy and penalized for reducing customer sales. According to Diane Munns, a member of the Iowa Utilities Board and president of the National Association of Regulatory Utility Commissioners (NARUC), "Profits must be decoupled from energy sales. We need to provide incentives to utilities to lower customer energy use so that energy efficiency can be measured as part of a profitable business."

For investor-owned utilities, shareholders are also part of the equation. "One of the first steps needed is to show utilities that there is a balance between the needs of their customers and those of their shareholders," states Kristine Krause, vice president of WE Environmental. "To paraphrase an old NARUC resolution," says Michael Dworkin, professor of law and director of the Institute for Energy and the Environment at Vermont Law School, "a utility's least-cost strategy for its customers should also be the most profitable strategy for its investors."

There are as many ways to value energy efficiency as there are utilities. "Utilities that do not own generation should be valuing efficiency as an alternative to a power purchase for a term equal to the life expectancy of the efficiency investment," says Dworkin. "And utilities that do own generation should make similar calculations; however, they should focus on the comparative capital costs of efficiency versus generation and transmission."

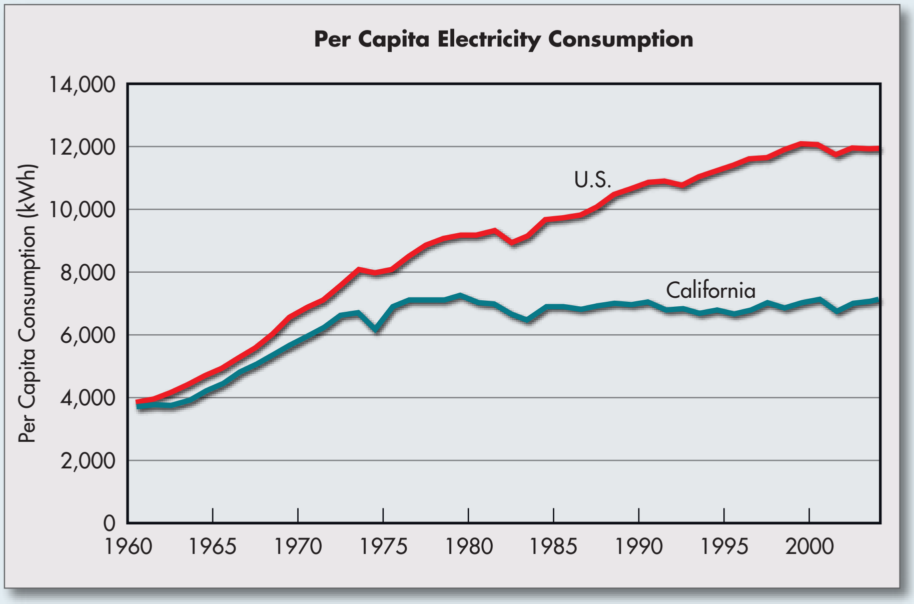
Any approach to incorporating the value of efficiency into rates must consider how generation itself is dispatched. Power providers turn first to the lowest-cost source of power: their baseload plants. As needed, they turn to medium-cost sources, and finally, to high-cost peak power units. Reducing energy use during peak periods

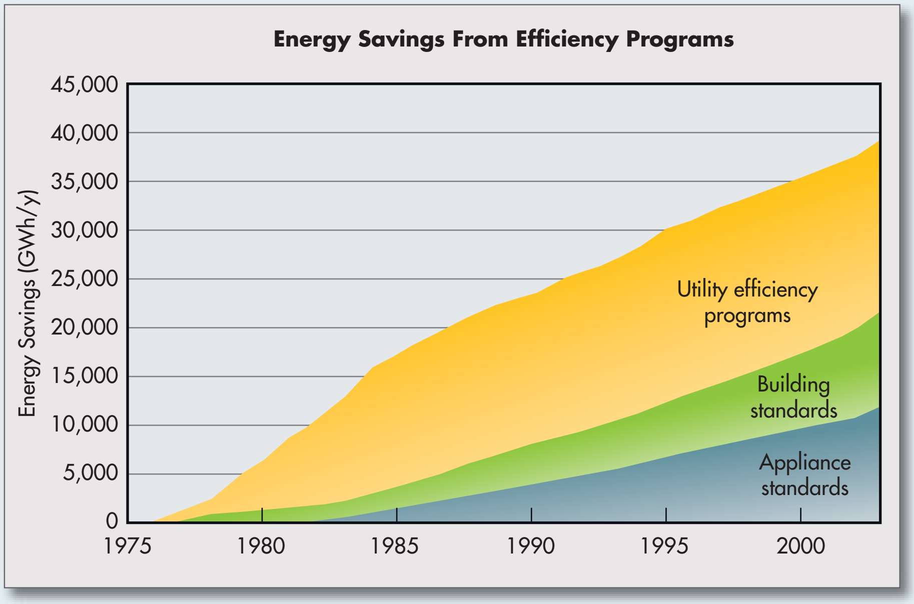
The California Experience

California is a prime example of what can be accomplished through sustained efforts in energy efficiency. The state's investments over the past 30 years in energy efficiency programs and improvements in building and appliance standards have held per capita electricity consumption constant at the 1975 level, while per capita use in the rest of the United States increased by nearly 50% (see graph). As a result, California saves about 40,000 GWh of electricity each year, roughly equivalent to 15% of the state's annual consumption. California's efforts have also reduced the state's peak demand requirements by 22%, allowing it to defer construction of 12,000 MW of peaking capacity over the past 30 years.

This progress has helped to stimulate the next big push and to justify it on both economic and environmental grounds. In January 2006, California kicked off the nation's most aggressive energy efficiency program, which will provide $2 billion in funding over the next three years. The state estimates that the investment will return nearly $3 billion in net benefits to the state's economy. The benefits include averting the construction of a 500-MW power plant each year and avoiding over three million tons of CO_2 emissions.

The state's regulators have recently adopted a plan requiring utilities to invest in energy efficiency whenever it is cheaper than building new power plants, and requiring that the savings attributed to energy efficiency be rigorously measured and verified.





is the best way to increase overall efficiency while also lowering the cost of electricity production. Unfortunately, most rates today are bundled rates—averaged across many customers and time periods—so consumers have no incentive to shift their energy use to more-economical, off-peak periods. According to Jeremy Bloom, EPRI's manager of power delivery asset management, "Most economists will say that until you create a pricing scheme that reflects the cost of energy by time of day or year, you won't have sufficient incentives for efficient energy use."

For regulators, end-use energy efficiency can be viewed as a tool to help expand the portfolio of options, create new capabilities and functionality in the power system, establish a more dynamic partnership between utilities and their customers, and respond to the global societal imperative of reducing greenhouse gases. Achieving these goals will require a renewed business model that goes beyond strictly selling electricity. Today's viable business models will have the following functions as well:

- removing the disincentive of lost revenues so that the utility does not lose money by selling less electricity
- providing incentives to promote energy

efficiency and demand response goals, such as allowing utilities to earn a rate of return on capital investments for efficiency
- placing energy efficiency resources on a competitive platform with new generation investments.

Innovative Markets

The deregulation experiments of the late 1990s led to broad-scale restructuring that redefined energy markets substantially. In some states, traditional utility functions were split, with power companies prohibited from producing the electricity they provided to customers. Such moves to promote competition separated generation investment decisions from the obligation to serve customers and changed electricity markets on both the wholesale and retail levels. Absent regulatory incentives, many utilities froze funding for programs that would reduce their ability to compete on a least-cost basis, and energy efficiency spending plummeted.

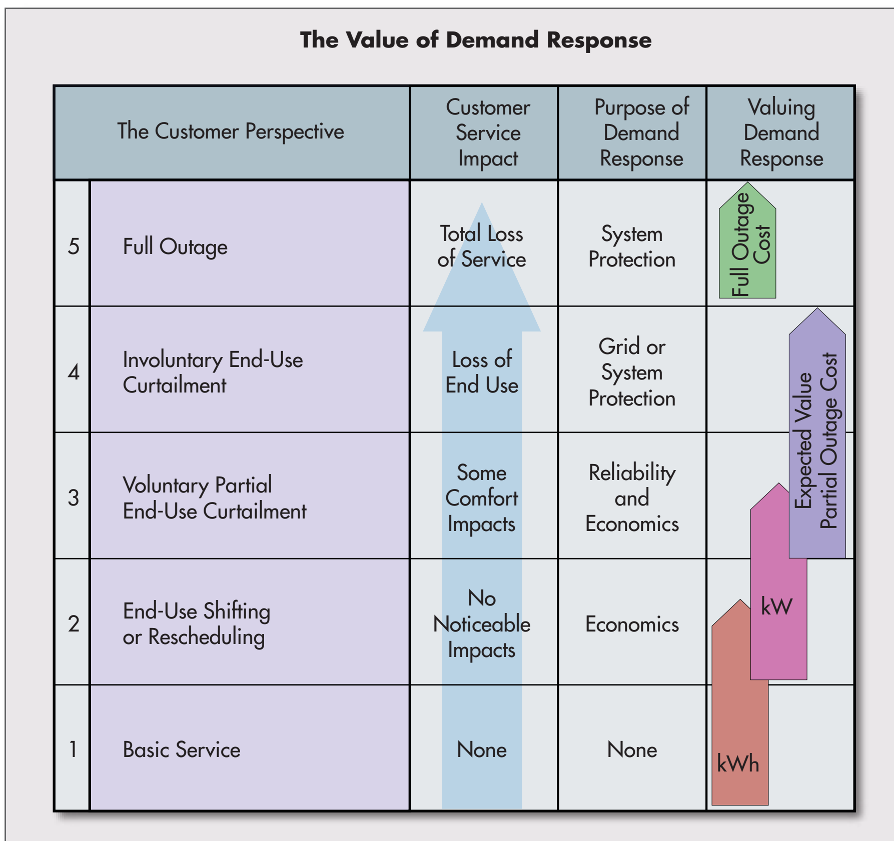
Strengthening or reinstatement of utility customer programs could provide important marketplace stimulation for efficiency goals. Energy audits, insulation programs, equipment servicing, rebates, buyback programs, and low-interest loans have all been effective in promoting efficiency in retail markets. Trade ally cooperation with home builders, contractors, service companies, and trade groups can further encourage the public to choose efficient appliances and equipment.

However, in terms of retail market offerings, emerging third-wave communication and device technologies will provide much-improved visibility and transparency on how value can be derived from efficiency and demand response. Dynamic systems will create a platform for creative new value offerings that will benefit both energy consumers and energy providers. Obvious possibilities will be time- and quality-differentiated rates and the easier purchase of nontraditional options such as green power or even "negawatts." With prices-to-devices capability, customers could be offered opportunity pricing for deferrable loads such as dishwashing or clothes washing. Essentially, power marketers will be able to respond to consumers' growing interest in customizing their purchases by allowing them to help design their own energy service packages through the smart meter–enabled consumer portal.

Wholesale market design features are also important, since they influence the vigor of competition, the accuracy of price signals, and the degree of coordination achieved among institutions on the supply side. And future innovations in market design must not introduce unintentional risk. In particular, designs must ensure that generation and transmission remain reliable and well coordinated, daily operations be immune to gaming and abuses of market power, and financial risks be well managed to enable the system to sustain exogenous shocks. Further, some mechanism must be found to provide adequate incentives for investment in generation and transmission and to ensure enough capacity margin to reduce price volatility.

Considerable work remains to be done before market designs can be successfully implemented:

- analyzing the successes and failures of recent power market experiences
- designing restructuring plans that minimize the overall risk of systemic failures
- ensuring efficient allocations of risk, especially financial solvency of default service providers
- mitigating market power to ensure generation adequacy
- creating and maintaining the market pull that will support these solutions.



Demand response has multiple dimensions of value at different levels of customer concern. Moving up from the supply of basic services, the purpose of demand response progresses from economic savings, in terms of kilowatthours of energy and kilowatts of capacity, to system reliability and protection against outages. (Source: Lawrence Berkeley Laboratories)

Restructured wholesale markets will inevitably transform a utility's role at the retail level. Notably, the regulatory compact's "obligation to serve," which characterized the previous era, may be recast to become an obligation to serve *at a price.* To protect consumers, regulators may require that a minimal service contract be offered as a default option, especially for residences.

The design of new markets and contracts will require a flexible regulatory approach and commitments on the part of all market participants to address the challenges of implementation. Markets will require new forms of service contracts, offered in a menu of options that can gain market share relative to current default minimal service. Designs are also needed for programs that offer provisions for insurance, curtailment, risk hedging, and other features.

Increasing Customer Satisfaction

While high-tech innovative systems may very well define the future of utility-consumer relationships, nearer-term opportunities to increase energy efficiency abound. In fact, energy efficiency technology available today can play a strategic role in increasing customer satisfaction—helping to maintain current customers and attract new ones—and can generally provide customers with more value for the energy they use.

What hasn't changed since the 1970s is that utilities are in a key position to deliver energy efficiency programs. "When we ask customers whom they rely on for energy efficiency information, they point to us," says Salt River Project's Richard Hayslip. "And I know we're not unique in this. Utilities are well positioned to be at the center."

Industrial and commercial customers seek efficiencies as a matter of economic survival, and they value energy providers that can help them compete. Justin Bradley serves as energy director for the Silicon Valley Leadership Group (SVLG), which represents some 200 well-respected employers in California's Silicon Valley region. "For commercial and industrial customers, voluntary energy efficiency has already decreased the carbon intensity of our economy enormously," he states. "This doesn't require a command-and-control regulatory approach. Instead, our motivation is economic sustainability in alignment with environmental and quality-of-life goals. Without sound economics, there is no *sustain* in sustainability." SVLG is currently collaborating in a partnership that includes local governments, nongovernmental organizations, academia, and businesses—including Pacific Gas and Electric Company—with a goal of voluntarily reducing CO_2 emissions in the region to 20% below 1990 levels by 2010.

Utilities can play a significant role as systems facilitators, offering new insight to system designers and helping commercial and industrial customers realize the greatest efficiencies systemwide. And the system may very well include the building itself. According to Marek Samotyj, an EPRI program manager in the Power Delivery and Markets sector, "Customers all too often choose to upgrade a single process or piece of equipment. While it may save energy, that approach may not offer the greatest benefit, and it may even cause other problems down the line. A high-technology control system, for example, may be too sensitive to operate in an outdated systems environment because of different harmonic distortion levels or power quality requirements."

Dworkin suggests that a combination of information and pricing packages targeted to specific markets can be very effective: "Focus on the places of greatest energy use. In Vermont or Wisconsin, visit all the dairy farms. In the Gulf States, visit the people who distribute air conditioning. In Manhattan, talk to managers of large commercial properties and manufacturers of HVAC chillers."

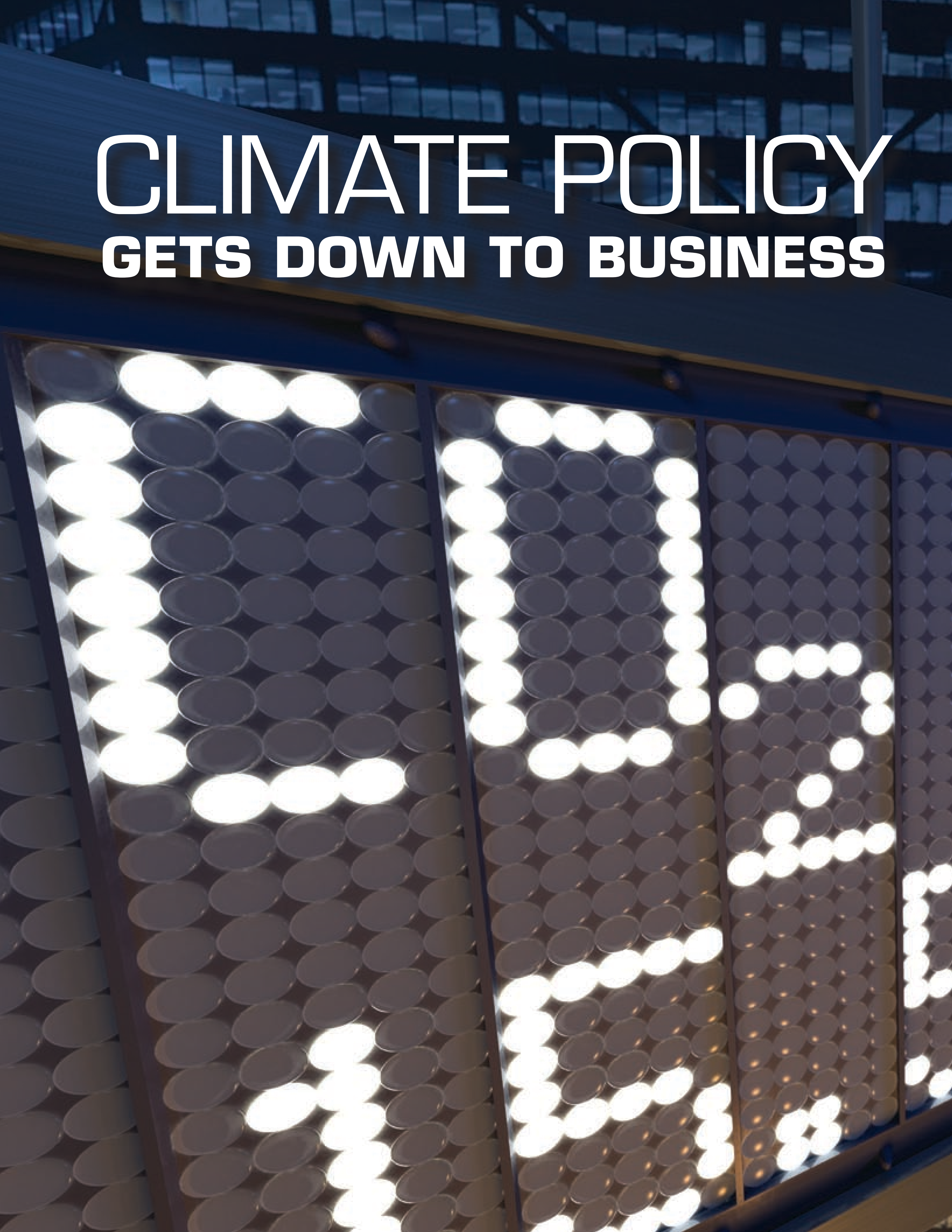
Fundamental to marketing energy efficiency programs and products is a good understanding of the perceptions and motivations of target customers, many of whom today are feeling the pinch from their energy bills. "For years we've been encouraging people to set back their thermostats," says Krause. "With the rise in the cost of energy, we've found that a certain set of people are motivated by tracking their utility bills to see if they can use less. We're sending our customers two years of data detailing how much energy they've used. They find this so interesting—I've had more people tell me this—they set up family contests to see who can figure out how to save the most. We wouldn't have gotten their attention if the price of natural gas weren't so high."

An unusual offering by Salt River Project is a prepay program whereby customers buy electricity in advance, put it on a card, and use that card to recharge their meter, so to speak. A device in the home tells them how much electricity they have left on the card; they can make adjustments to maximize their energy use; and most important, their use is communicated in dollars. "It's a clear signal to consumers how much electricity they're using and how much they have left," says Hayslip. "It forces them to pay attention, and they tend to use a lot less electricity." The program was initiated for people who had credit problems, but it was expanded to include individuals who want to closely monitor their electricity expenditures. It now serves 40,000 customers.

Independent of approach, all agree that this is the time for action. "Energy demand is on the rise, and energy prices are increasing," says Munns. "Energy efficiency is the least expensive and most environmentally friendly way to approach adequacy and price issues. It will not replace the need for new infrastructure and supply, but it has a definite role."

This article was written by Brent Barker and Lucy Sanna. Background information was provided by Art Altman (aaltman@epri.com), Steve Gehl (sgehl@epri.com), Clark Gellings (cgelling@epri.com), Joe Hughes (jhughes@epri.com), Revis James (rejames@epri.com), and Ellen Petrill (epetrill@epri.com).

CLIMATE POLICY
GETS DOWN TO BUSINESS



The Story in Brief

Market-based policies are beginning to emerge in the economies of nations facing binding constraints on greenhouse gas emissions under the Kyoto Protocol. And while the United States has declined to sign the protocol, substantive action is taking place on a variety of domestic fronts. A number of market-based initiatives are gaining traction on the state and regional levels, and seven northeastern states will soon kick off a mandatory cap-and-trade system that will require power plants to reduce carbon dioxide emissions. And at the federal level, policy discussions are beginning to move beyond a sole focus on setting near-term caps for carbon toward developing the technology that will make longer-term reductions achievable.

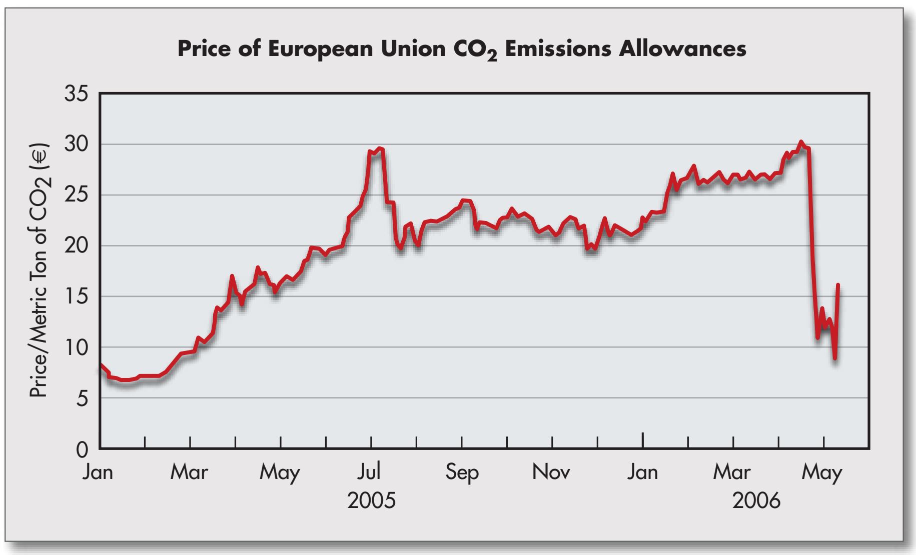
The issue of controlling carbon dioxide (CO_2) emissions—once thought of exclusively as the business of national governments—is now also working its way into state and local decision-making processes. And perhaps the most important signals are emanating from corporate boardrooms, where executives are both responding to demands for accountability on CO_2 and trying to plan for a very uncertain future with associated financial risks. In short, the science, the politics, and the business aspects of climate change have converged in efforts to address the climate issue—a confluence that has already sparked action.

Implementing Kyoto

The Kyoto Protocol, which entered into force in early 2005, set two important precedents. First, it required industrialized nations that signed on to the protocol to implement binding measures to reduce their average annual emissions. Second, it incorporated market-based flexibility mechanisms that had been advanced by U.S. negotiators as a means of reducing economic disruptions while achieving emissions reduction targets. The core of this market-based approach is the cap-and-trade system: total emissions of CO_2 are capped at a level expected to achieve a desired result—in the case of Kyoto, a level lower than historical emissions—and allowances (credits) equaling this total are distributed to participants. A country that cannot reduce its emissions sufficiently on its own can then cover the shortfall by purchasing allowances from countries that have met their emissions quotas and have credits to sell or from developing countries, not subject to mandatory caps, that can create credits from approved projects. One of the advantages of this system is its economic efficiency: it encourages reductions to be made in places, and by means, that are less expensive while still hitting overall emissions targets.

By May 2006, European Union members had reconciled accounts from their first year of a new emissions trading scheme in preparation for making the reductions needed to achieve their Kyoto targets. The results highlighted both the potential and the difficulties of building new markets from scratch. The market price for CO_2 under the European Union Emissions Trading Scheme (ETS) opened at 8 euros (€) per metric ton of CO_2 (tCO_2) in January of 2005, climbed steadily, peaked at almost 30€, and then hovered at just above 20€ through December. In late April 2006, however, several weeks before the ETS was to officially release the year's compliance data, the news broke that 21 of the 25 member states had come in below targets; as a result, the allowance market plunged by over 70% in a few days, stabilizing again by mid-June at around 15€/tCO_2.

While some have claimed that the market volatility in CO_2 credits reflects basic flaws in the cap-and-trade approach, most experts see it as an inevitable part of building a practical new system. "This is why the EU-ETS was designed with a 2005–2007 pilot phase—to test the concepts and mechanisms and shake out problems for the long haul," says Tom Wilson, manager of EPRI's Greenhouse Gas Reduction Option Program. One such problem clearly centers around the national allocation plans for phase 1, which were put together according to emissions histories and nonstandardized assumptions provided largely by the industries themselves. These allocations will almost certainly have to be changed. "Phase 2 trading, which will be in effect for 2008–2012, is much more important, as the trading scheme—which covers some 46% of EU CO_2 emissions—will be one key tool to help the member states meet their Kyoto emissions targets," says Wilson. "This first phase has been very valuable in providing an accurate baseline for actual emissions and for identifying other issues, such as the need for longer-term signals to guide energy investments. Negotiation of phase 2 caps and allocations is already under way between the EU Commission and member countries. The phase 1 experience will be very useful in guiding the next step of the ETS toward the real emissions reductions required by Kyoto."



Prices of CO_2 credits under the European Union Emissions Trading Scheme have been volatile, especially in April, when first-year emissions compliance data revealed that a majority of EU member countries had come in below targets. Caps and allocations for phase 2 trading, which will be in effect for 2008–2012, are expected to be tighter. The trading scheme provides a key tool for achieving EU emissions targets agreed to under the Kyoto Protocol.

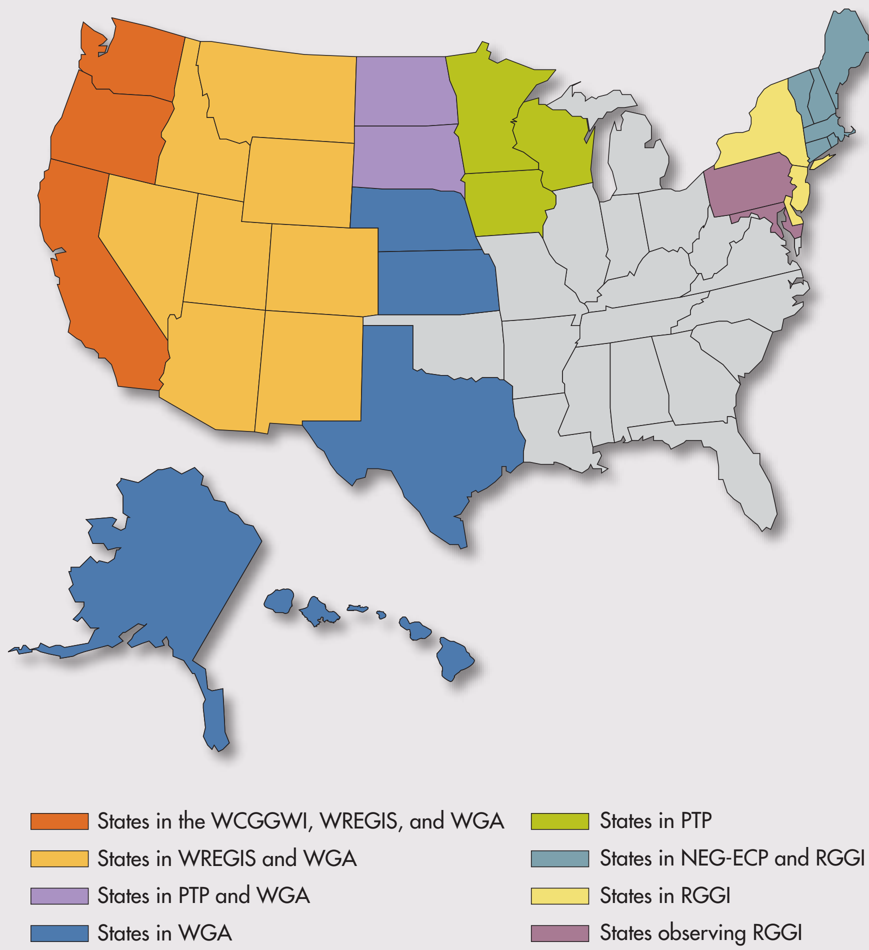
The Northeast Shows Initiative

As Europe works to refine the nuts and bolts of the Kyoto accord in the international sphere, the United States' first mandatory cap-and-trade initiative for greenhouse gases is gathering steam in the Northeast. The Regional Greenhouse Gas Initiative (RGGI) was launched in April of 2003, when New York governor George Pataki invited fellow governors in the region to participate in the design of a mandatory CO_2 cap-and-trade program for power plants. On December 20, 2005, Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont committed to implementation of the program, as outlined in a memorandum of understanding signed by the participating states' governors. The program will apply only to generating facilities that have a nameplate capacity of at least 25 MW, that rely mostly on fossil fuels, and that supply 90% or more of their power to the electricity grid. RGGI is designed to stabilize CO_2 emissions from regulated power plants in the seven-state region at approximately 1990 levels from 2009 to 2014 and then reduce them by a total of 10% during a second five-year compliance period.

This Northeast initiative will be a direct functional descendant of the U.S. Acid Rain Trading Program, the nation's first large-scale experience with emissions trading in any form and still the world's poster child for successful application. Initial emissions permits—allowances—will be issued to cover current levels of CO_2 emissions, with three-fourths of the allowances distributed free to plant owners and the rest auctioned off by the states. Auction revenues will then be used to encourage energy efficiency initiatives, deploy nonemitting generators, and support R&D on advanced energy technologies. Plant owners may then trade allowances or earn a limited number of additional allowances by investing in "offset projects" that reduce greenhouse gas (GHG) emissions from sources other than power plants. Such offset activities could include, for example, boosting efficiency in the use of heating fuels, forestation of nonforested land, and reducing methane emissions from livestock operations.

While RGGI has many champions in business and politics, critics have identified key uncertainties and limitations that could constrain its practicality and effectiveness. The biggest concern—which caused Massachusetts and Rhode Island to pull out of negotiations before the final agreement was signed—is the possibility that the price of carbon will impose unacceptable cost burdens on businesses and other electricity consumers. As a hedge against such uncertainty, a "safety-valve" provision has been included in the program design, which will provide regulated

U.S. Regional Climate Policy Initiatives

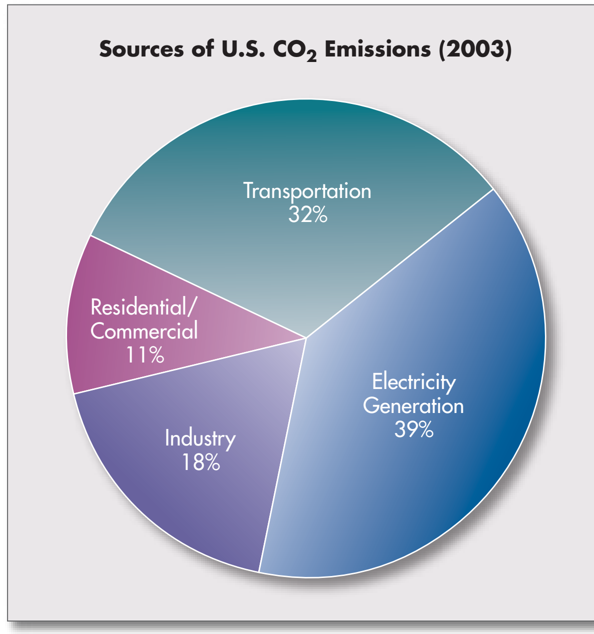


More than 30 states are involved in one or more regional initiatives on climate change and clean energy. The West Coast Governors' Global Warming Initiative (WCGGWI) is working on a coordinated strategy for reducing greenhouse gas emissions. The Western Governors' Association (WGA) is focused on efficiency and renewables and is creating the Western Renewable Energy Generation Information System (WREGIS) to track renewable energy credits. Powering the Plains (PTP) is developing climate policies that involve both energy and agriculture. The New England Governors and Eastern Canadian Premiers (NEG-ECP) prepared a climate action plan in 2001 that includes both short- and long-term goals. And the Regional Greenhouse Gas Initiative (RGGI) is developing the nation's first mandatory regional cap-and-trade system for CO_2 emissions. (Source: Pew Center on Global Climate Change) facilities greater flexibility in compliance if CO_2 allowance prices settle above \$11/tCO_2. In addition, energy economists generally agree that an efficient market-based program must eventually cover all GHG sources—not just electricity generating facilities. Restricting emissions programs to individual states or regions also raises a variety of other issues, including the problem of "leakage." This term describes the likelihood that price differentials between a controlled region and surrounding areas will lead to increased imports of power from distant generators not covered by the standards—potentially raising overall emissions levels.

The final details and ultimate impact of RGGI are hard to predict. Nonetheless, the program will establish and demonstrate—on U.S. soil—the complex of rules and institutions necessary to develop, implement, and maintain a mandatory emissions trading program. And many experts believe it may provide important precedents for a future national program.

Meanwhile, a variety of other regional and state-level initiatives are also taking shape. California, Washington, and Oregon, for example, have formed the West Coast Governors' Global Warming Initiative to coordinate strategy for reducing GHG emissions. The Western Governors' Association (WGA) has created the Clean and Diversified Energy Initiative, representing 18 western states, to explore various ways of increasing efficiency and using renewable energy resources in those states' electricity systems. WGA has also created a system to track renewable energy credits across 11 states in order to facilitate future trading. Five midwestern states and the Canadian province of Manitoba have formed an initiative, called Powering the Plains, to develop climate policies that involve both energy and agriculture. This initiative also includes a renewable energy tracking system.

In addition to such regional activities, 28 individual states have adopted GHG action plans, and 20 have set a renewable energy portfolio standard (RPS) for electricity generation. California, for example, has set GHG targets that include reducing emissions to 2000 levels by 2010 and to 1990 levels by 2020. In addition, the state's RPS regulations (currently under review by various government agencies) would require retail electricity providers to purchase 20% of their power from renewable energy resources by 2010 and 33% by 2020. Similarly, New York has set a GHG emissions target of 5% below 1990 levels by 2010 and 10% below 1990 levels by 2020. The state's RPS standard calls for 25% of electricity to come from renewable sources by 2013.



Electricity generation produces the greatest percentage of CO_2 emissions in the United States, but the transportation and industrial sectors produce large volumes as well. An effective and economically efficient emissions reduction policy will necessarily include restrictions on all sources of carbon. (Source: Energy Information Administration)

A common limitation of many current regional and state initiatives is that they apply just to electricity generating facilities, which account for only about 39% of CO_2 (30% of GHG) production in the United States. In response, some states are making efforts to broaden the scope of emissions regulations, especially to include the transportation sector, which accounts for a third of the country's GHG emissions. California, in particular, has taken the lead by adopting a requirement to reduce GHG emissions from new cars and light trucks by 30% by 2016. In addition, several states have established policies that encourage higher vehicle efficiency and use of low-emission fuels.

Grassroots Concern

None of these state and regional initiatives could have solidified without substantial public support. Over the past quarter century, media attention to the possible effects of human activities on global climate has waxed and waned in the United States, generally increasing when new scientific findings are announced or when extreme weather dominates the airwaves. Nevertheless, public apprehension has risen steadily over this period: according to an October 2005 survey by *Fox News,* more than three-quarters of the U.S. population believes that climate change is occurring, and most believers assign at least part of the blame to human activities. And while federal programs have yet to formulate a mandatory CO_2 emissions reduction program, 43 U.S. senators did express support for binding constraints on greenhouse gas emissions during the 2005 energy policy debates. Media attention to the climate issue really caught fire in the first half of 2006, with in-depth coverage from CNN, HBO, ABC News, and National Geographic and special issues of *Time* and *Newsweek.* Al Gore's documentary film, *An Inconvenient Truth,* has broken out of the traditional art-house circuit to play in many cineplex theaters across the country.

Disquiet over the potential effects of climate change has also begun to gain traction through a novel form of activism. Advocacy groups, institutional investors, religious groups, and foundations with a focus on environmental stewardship and corporate responsibility have pushed the issue in financial terms. Targeting the electric power, automotive, oil and gas, manufacturing, real estate, and financial services sectors, the groups have filed shareholder resolutions that request corporate risk disclosure relating to climate change, as well as information on actions taken and plans developed to reduce emissions. Included in the list are the 50 publicly traded power companies that rank highest in annual CO_2 emissions.

Internationally, the Carbon Disclosure Project (CDP) is organizing requests for information from the *Financial Times* 500—the top companies in the world as ranked by market capital—on behalf of more than 150 institutional investors that together manage more than $21 trillion in assets. These investors include the California Public Employees' Retirement System and the California State Teachers' Retirement System—the second- and third-largest U.S. public pension funds. Companies are asked to characterize risks and opportunities relating to physical climate change, climate policy, and climate adaptation. In 2005, the CDP achieved a 70% response rate, and 90% of respondents identified both risks and opportunities, generating the information needed by investors looking to identify winners and losers in the carbon-constrained future.

Utility Initiatives

American Electric Power (AEP), among the largest generators of electricity in the country, was the first major U.S. electricity company to respond to a shareholder resolution on climate risk disclosure. On August 31, 2004, AEP issued a report detailing its voluntary emissions reduction actions and emphasizing that actions taken to date have positioned the company well to comply with a possible future mandatory program. AEP noted that "the central challenge the company faces is that of making decisions about large investments in long-lived assets in a setting of uncertain public policy and rapidly evolving technology." A number of other large utilities, including TXU, Cinergy (before its merger with Duke Energy), DTE Energy, FirstEnergy, Progress Energy, and Southern Company, have issued shareholder reports and position statements on climate policy issues. One position is common in all the high-profile shareholder reports: the acknowledgment that climate change is a long-term societal issue and serious business challenge that cannot be addressed without a substantial and sustained public-private commitment to research and development and to the widespread deployment of advanced energy technologies.

As AEP emphasized in its report, the coming decade's capacity additions are being planned now, with no real information on how national carbon constraints—constraints that many view as inevitable—will eventually be framed. From an investment perspective, reducing CO_2 emissions will present tough challenges, but continued uncertainty about the longer-term direction of policy may be worse, considering that today's investments may not be compatible with tomorrow's rules. In the absence of mandatory federal programs, some companies are participating in voluntary initiatives, at least in part to gain experience for the future. The voluntary programs provide an opportunity to develop new strategies for GHG emissions inventory management, tracking, and reporting. They may also provide a built-in hedge on financial risks by putting a company in a better position to respond to future changes in regulations and the business climate.

One of the most common approaches is to set an absolute GHG emissions target at the corporate level. This process involves determining current emissions for a baseline year or period, setting a specific goal in terms of tons of GHG to be emitted, and specifying a commitment period for achieving the needed reductions. For example, Cinergy—now merged with Duke Energy—has committed to achieve a 5% reduction from its 2000 GHG emissions level by 2010–2012, averaged over the three-year period. The company has also pledged to spend $21 million on reduction efforts over the five-year period leading up to that, from 2004 to 2009. Similar approaches involving absolute emissions targets have been taken by a number of companies, including AEP, DTE Energy, Entergy, Exelon, Manitoba Hydro, and TECO Energy.

An alternative approach is to make a voluntary commitment to reduce the GHG intensity of a company's generation, in terms of emissions per megawatthour. Again the first step is to establish a baseline intensity level, set an intensity goal, and specify a commitment period. This procedure has been taken by major trade associations, on behalf of their members, in cooperation with the U.S. Department of Energy. Specifically, the utilities involved in the Power Partners initiative have agreed to reduce their GHG emissions intensity by 3–5% below baseline (2000–2002) by a commitment period of 2010–2012. Some individual utilities have adopted more-stringent GHG intensity goals. FPL Group, for example, has committed to an 18% reduction in emissions per megawatthour from 2001 to 2008. PSE&G has taken a combination approach that includes both a 15% reduction in absolute emissions levels below 1990 baseline by 2006 and an 18% reduction in emissions intensity from 2000 to 2008.

Utilities—as well as companies from other industries—that establish a 5–10-year corporate-wide emissions reduction goal that represents an improvement over business-as-usual practices for their sector are eligible to join the Environmental Protection Agency's Climate Leaders program. This government-industry initiative is designed to help companies develop long-term emissions reduction strategies and to "strategically position themselves as climate change policy continues to unfold."

Climate Leaders also requires participants to inventory and report annually to the EPA on their GHG emissions. In turn, they receive information on industry best practices in GHG management.

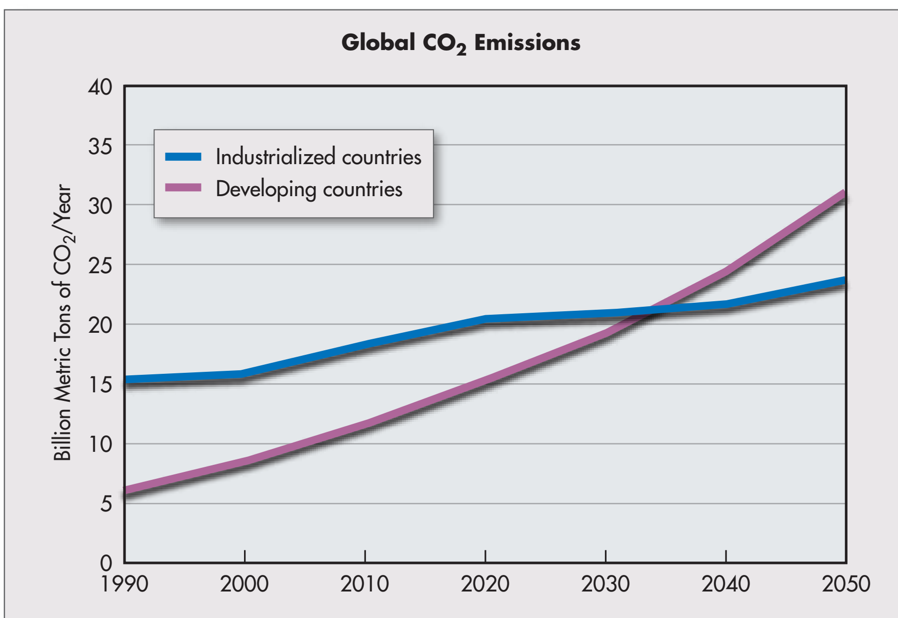
Several utilities have also become members of the Chicago Climate Exchange (CCX) in order to trade emissions allowances. Members of CCX make a voluntary, but legally binding, commitment to reduce GHG emissions—4% below the 1998–2001 baseline period by 2006 and 6% below baseline by 2010. They can then trade emissions allowances in parcels of 100 tCO_2, as well as carbon credits for offset projects, such as building renewable energy facilities. CCX recently announced that it will also accept European ETS allowances to be used for compliance, although actual inter-exchange trading has been very limited because of substantial price differences. Although CCX prices have also been volatile, they have generally remained below $5/$tCO_2$—a fraction of the price in Europe. Economist Richard Sandor, who helped establish CCX, says that he expects GHG emissions to eventually become "the single largest commodity in the world . . . bigger than crude oil."

The Madisonian Approach

What do these many state and regional developments mean for the big picture? The Kyoto Protocol outlined a legally binding top-down, globally integrated, market-based approach for achieving its near-term emissions targets in an economically efficient manner. The process that is actually emerging as companies, regions, and nations prepare for a carbon-constrained future does not fit this description very well. David Victor, director of the Program on Energy and Sustainable Development (PESD) at Stanford University and adjunct senior fellow at the Council on Foreign Relations, sees the decentralized initiatives as a necessary and familiar development. "On a global level, fragmentation is occurring because individual nations have their own interests, the developed and developing worlds have incompatible institutions, and international law is too weak to reconcile them," Victor explains. Decentralized programs can allow countries that aren't willing to sign on to Kyoto to participate in CO_2 reductions in a meaningful way.

In a recent article in *Science,* Victor and his PESD colleagues call the decentralized push a Madisonian approach to climate policy, because it resembles "the messy federalism that James Madison embraced in the U.S. Constitution." According to Victor, global institutions are too weak to monitor and enforce what is, in effect, a new monetary system based on emissions credits. By contrast, the strength of a bottom-up approach is its ability to tap stronger national and regional institutions for governance. The Madisonian approach would engage developing countries on their own terms, Victor says, by encouraging them to invest in infrastructure improvements that would help manage local air pollution problems while also cutting carbon emissions.

In the United States, decentralized, bottom-up responses like RGGI are emerging in advance of federal action because of regional disagreements on political and economic issues similar to those in play on the world stage. With the myriad decentralized plans now evolving, the longer-term policy challenge becomes one of how best to learn from these efforts and to knit them into the much more efficient national and global markets for carbon that were envisioned a decade ago. In the meantime, the federal focus has been largely on the energy technology side of the climate conundrum, an area in which the United States may be assuming the lead (see accompanying article, "Generation Technologies for a Carbon-Constrained World").



If current trends continue, CO_2 emissions from the developing world will surpass those of industrialized nations in about 30 years. Finding incentives that encourage developing nations to participate in emissions reduction will be an essential part of future global climate agreements. (Source: Richard Richels)

Importance of Technology Policy

Despite the continuing impasse at the national level, several legislative proposals aimed at reducing GHG emissions have been introduced over the past two years. The most significant legislation with some climate-related provisions that has actually been enacted is the omnibus Energy Policy Act, which was signed into law in August 2005. This bill established loans to deploy technology for GHG intensity reduction, charged the secretary of state with providing assistance to developing countries on projects to reduce GHG intensity, and established an export initiative for GHG emissions reduction technology. Pointedly, it did not set mandatory emissions targets.

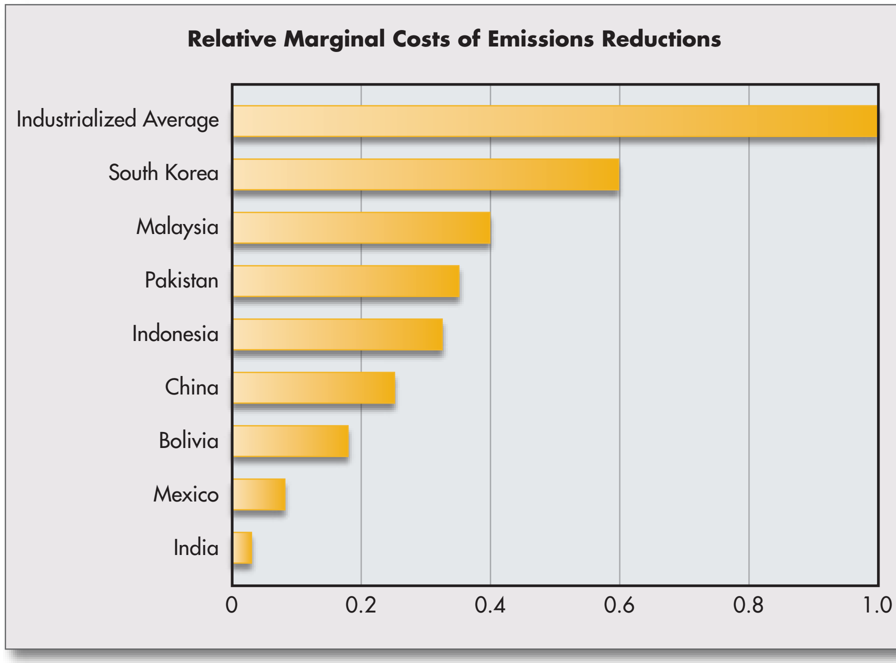
Such targets, however, have featured prominently in other recent legislative proposals. Senator John McCain (R-AZ), for example, has introduced a bill that would cap the GHG emissions of the electricity, manufacturing, commercial, and transportation sectors (85% of total emissions) at the 2000 level by 2010. Companies involved would be able to trade emissions credits. Senator Jeff Bingaman (D-NM) has proposed a bill that would establish annual targets for GHG emissions and allow regulated companies to exceed their targets by paying a safety-valve price for emissions allowances. This proposal was based on recommendations of the National Commission on Energy Policy and also contains provisions for promoting the use of clean energy technologies in developing countries. More recently, Senator Dianne Feinstein (D-CA) has circulated draft legislation aimed at reducing GHG emissions by 7.25% from today's levels by 2020, through a cap-and-trade system involving "all companies that emit significant greenhouse gases at a single facility."

No matter which proposals, reduction targets, and timetables Congress eventually turns into law, one thing is clear: successful development of advanced technology will be the prerequisite for making them work. And with cost being the major sticking point in virtually all proposed plans, economic efficiency and incentives for technology development will be key issues.

"Economic efficiency—that is, achieving our environmental goals at least cost—is critically important," said Richard Richels, EPRI technical executive for global climate change research, in recent testimony before the Senate Energy and Natural Resources Committee workshop on design elements of a market-based greenhouse gas regulatory system. "The difference between an efficient and inefficient system can be on the order of hundreds of billions of dollars and can determine the success of the program." In addition, he told the committee that "technology advances are central to controlling the cost of addressing climate change. The value of near-term policies will ultimately be judged by how effectively they create technological innovation."

Tom Wilson stresses the need to include an explicit technology policy as part of a broader climate policy: "Even a climate policy that leads to an economically efficient price on carbon emissions is unlikely, by itself, to produce the needed technological breakthroughs. In particular, there is a risk that stringent, near-term emissions limitations would only encourage deployment of better existing technologies, rather than stimulating fundamental, long-term technology improvements. R&D must be increased substantially now in order to enable widespread deployment of the advanced emissions reduction technologies that will ultimately be needed to stabilize atmospheric concentrations of greenhouse gases."

This article was written by Christopher R. Powicki and John Douglas. Background information was provided by Tom Wilson (twilson@epri.com).



Flexibility in when and where emissions reductions are pursued is key to achieving global atmospheric stabilization objectives at minimum cost. A number of countries in Asia and Central and South America can reduce emissions at a fraction of the cost of reductions in industrialized countries. (Source: W.D. Montgomery)

GENERATION TECHNOLOGIES

FOR A CARBON-CONSTRAINED WORLD

The Story in Brief

Planning future generation investments can be difficult in the context of today's high fuel costs and regulatory uncertainties. Of particular concern are sharp changes in the price of natural gas and the possibility of future mandatory limits on the atmospheric release of CO_2. Research on advanced coal, nuclear, natural gas, and renewable energy technologies promises to substantially increase the deployment of low- and non-carbon-emitting generation options over the next two decades. Prudent power providers are likely to invest in a number of these advanced technologies, weighing the advantages and risks of each option to build a strategically balanced generation portfolio.

Climate change presents a challenge that is fundamentally different from the kinds of regional air pollution issues the international community has faced before. The impacts of climate change are likely to vary considerably across geographic regions, occur over a timescale of decades to centuries, and be influenced by all greenhouse gas (GHG) emissions from everywhere on the globe. The actions needed to manage climate risks will involve wholesale infrastructure changes on the part of societies worldwide, as well as long-term commitment to unprecedented technology development and deployment.

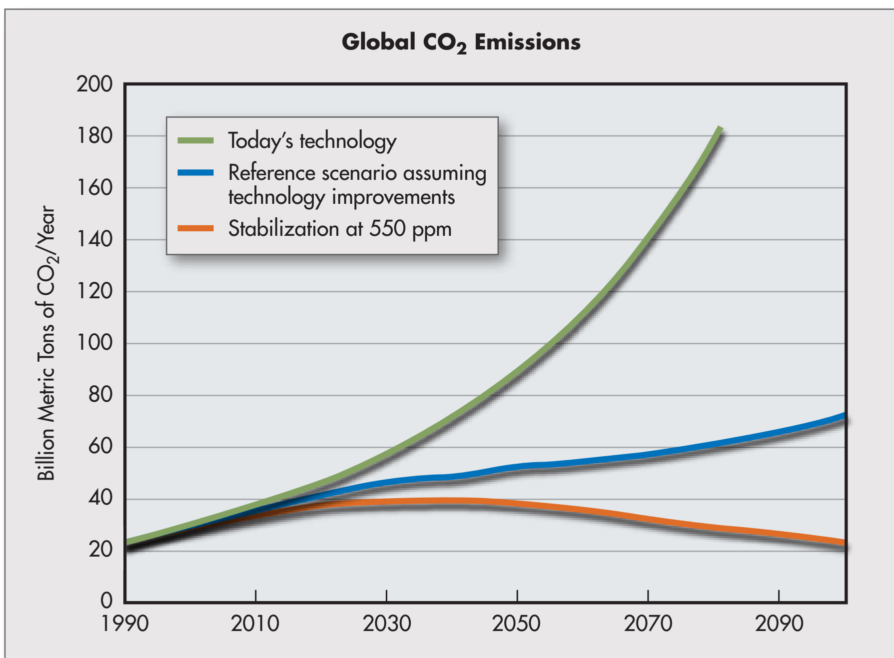
The electric power industry will inevitably play a key role in stabilizing GHG emissions, both because fossil-fired power plants represent a major source of carbon dioxide (CO_2) and because electricity generation provides the most promising way to utilize a variety of primary energy resources to meet society's growing energy needs. Some generation technologies, such as nuclear power and renewable resources, inherently produce no or very low GHG emissions. Others, such as advanced combustion options for coal and natural gas, are amenable to integration of CO_2 capture processes, enabling separation and storage for centuries.

Because some of today's CO_2 emissions will reside in the atmosphere for hundreds of years, the atmospheric concentration of CO_2 will continue to rise even if the rate of man-made emissions is initially slowed and then reduced; only when technologies with minimal emissions achieve sufficient global market share will the atmospheric concentration begin to stabilize. A major task for the worldwide electric power industry, therefore, will be to develop and deploy a portfolio of technologies that can provide emissions trajectories consistent with specific goals for stable atmospheric CO_2 concentrations. This task is made particularly difficult by the lack of international consensus over what those goals should be or what effect various concentration levels might have on climate. Target concentrations for stabilization currently being discussed range from 450 to 750 parts per million (ppm). For any value in this range, the CO_2 emissions reductions that will ultimately be needed will require a substantial replacement of current CO_2-emitting generation technologies.

Need for New Technologies

Stabilizing atmospheric concentrations of GHGs will require development and widespread deployment of power generation technologies that are essentially emissions free—advanced versions of today's nonemitting nuclear and renewable technologies and advanced fossil power systems with reduced CO_2 emissions. Currently, carbon-based fuels account for about 85% of the world's energy use, so reducing CO_2 emissions from fossil fuel combustion will require a massive transition. As a first step, the energy efficiencies of both existing and new fossil-based generating technologies can be increased, and RD&D on CO_2 capture technologies can be accelerated.

A major factor determining the pace of change will be the time required to bring about an efficient capital stock turnover in electric power plants. According to the U.S. Department of Energy's Energy Information Administration (EIA) forecasts—which assume no constraints on carbon emissions—total electricity sales in the United States will increase 50% between now and 2030, and power plants using coal and natural gas will account for about 90% of new generating capacity. Nonemitting nuclear and renewable resources will provide most of the remaining capacity growth. Using "reference case" assumptions, EIA expects only about half a dozen new U.S. nuclear plants to be built before 2021, taking advantage of tax incentives included in the Energy Policy Act of 2005, with no further additions anticipated once the incentives expire. Substantial reduc-

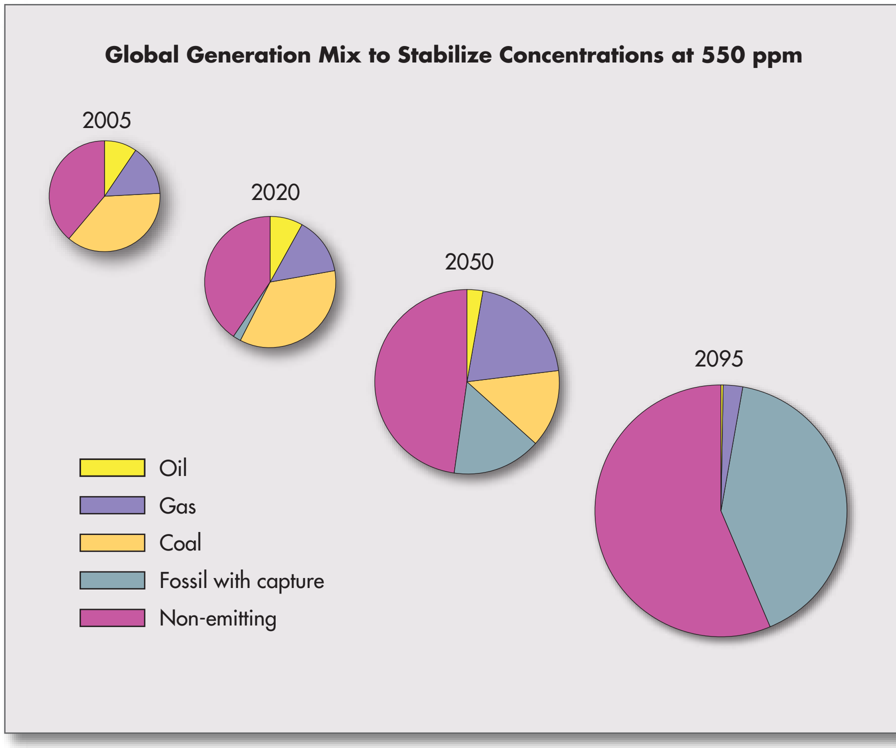


While near-term climate policies typically target certain percentage reductions in carbon emissions, the longer-term goal is stabilization of atmospheric concentrations of CO_2 at a specified level, such as 550 parts per million (ppm). Future reference scenarios typically assume that energy technologies will improve over time. Improved versions of current technologies are expected to substantially slow the growth in CO_2 emissions but will not lead to stabilization. Widespread deployment of truly advanced, low- and non-emitting technologies will be needed to drive emissions toward zero and stabilize atmospheric CO_2 concentrations.

tions in the cost of building new plants, however, as anticipated by many industry experts, could lead to construction of several times more plants over the next two to three decades and fundamentally change CO_2 emissions projections.

Internationally, China is embarking on a major effort to build new, more-efficient coal power plants and plans to build 27 new nuclear power plants by 2020 as well. In India, as in China, coal is expected to remain the dominant fuel, and advanced coal technologies are already being adopted; 8 nuclear plants are under construction there.

Considering the projected demand growth and generation mix, it is crucial that research on carbon capture and advanced generation options be adequately funded to ensure that commercially competitive low- or non-emitting technologies are available to be selected and deployed on a significant scale over the next 20 years. Among industrialized countries, public funding for energy research has been falling for almost two decades, and while the funding level has recently stabilized, only a small fraction is targeted at the suite of new technologies that could play a significant role in atmospheric CO_2 stabilization. Greatly enhanced R&D funding will be needed to develop a broad set of low- or non-emitting technologies that can offer sufficient options to meet future deployment needs. Cost reduction will be a particularly important consideration, according to EPRI technical executive Steve Gehl: "Today, with the exception of nuclear, most non-emitting power generation options are more expensive than conventional power plants. With further technology development, however, carbon-free generation will become increasingly competitive."



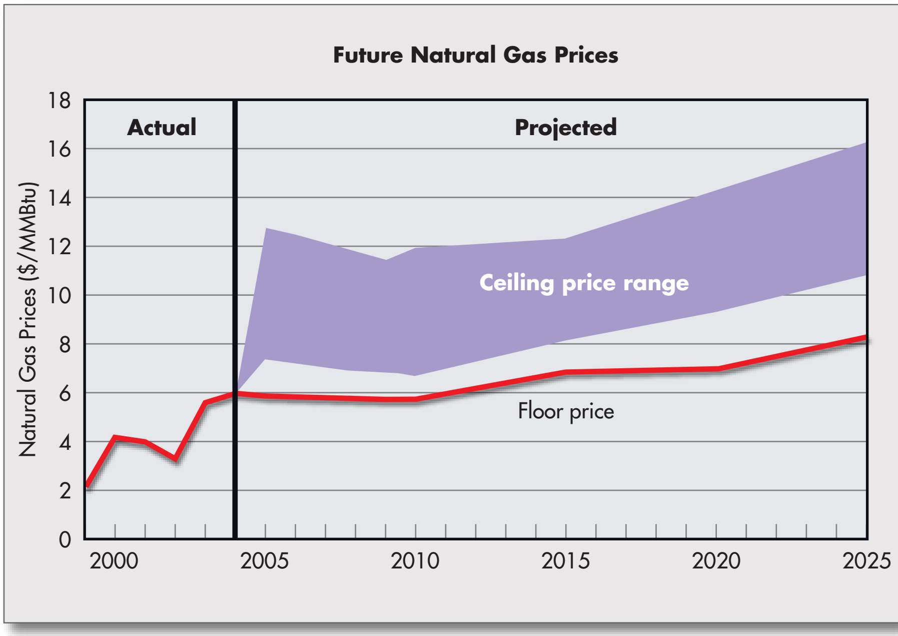
Global electricity use is expected to grow by a factor of 5 by the end of the century. To achieve this growth and contribute to stabilization of atmospheric CO_2 concentrations at 550 ppm, electricity will have to migrate from a generation mix that is mostly carbon-emitting today to one that is essentially non-emitting by 2095. Such a change will require tremendous increases in nuclear and renewable generation and the predominant use of carbon capture and sequestration with fossil-fueled generation.

Two Key Uncertainties

Assuming sufficient R&D funding and the successful development of several low- and non-emitting generation technologies, the market choices among the new alternatives will depend in large measure on two key uncertainties: the price of natural gas and the cost of CO_2 emissions controls and/or market credits.

Over the past five years, the price of natural gas in the United States entered new territory, going from less than $3 per million Btu (MMBtu) to over $13 in the last quarter of 2005 and then falling back to $6 this summer. Winter futures prices are trading at over $10/MMBtu through 2009. The increase is due to a variety of factors, ranging from declining production to increases in demand to supply interruptions caused by Hurricanes Ivan and Katrina. Over this period, natural gas prices have risen significantly in Europe as well. A particularly disturbing trend for the United States has been the shrinking of domestic gas reserves, both in size and pressure. For many years, exploration in the mature U.S. provinces has primarily targeted low-risk projects, creating an ever-increasing need to drill more wells to offset rapid declines in production from existing wells. As a result, about half of today's supplies come from wells that are less than three years old.

The largest potential source of gas to relieve the global supply-demand imbalance would come through increasing shipments of liquefied natural gas (LNG). International trade in LNG provides an opportunity to make commercially available some large gas reserves in regions, such as sub-Saharan Africa and South America, that do not have access to major gas pipeline networks. For example, by tapping into vast natural gas resources that were previously uneconomic, Qatar has recently become the world's leading exporter of LNG, which it sells to markets in Asia, Europe, and North America. Even countries with access to pipelines may find advantages in using LNG to increase exports or imports: Iran, for example,



The future price of natural gas is a key uncertainty that will affect generation technology choices over the coming decades. The price of coal is assumed to set the floor price for gas, while the price of oil—itself a far-from-stable commodity—defines a ceiling. Increased availability and global transport of liquefied natural gas (LNG) is expected to moderate gas prices considerably.

recently pursued a $70 billion agreement with China to sell 250 million tons of LNG over the next 30 years.

EPRI expects U.S. LNG imports to rise from about 0.65 trillion cubic feet per year (TCF/y) in 2004 to as much as 4.0 TCF/y by 2010. Local opposition to LNG facilities and a variety of regulatory hurdles, however, could slow the pace of development. Meanwhile, the ability of the electric power sector to shift between gas and other fuels provides an effective hedge on electricity prices from spikes in natural gas prices.

The ceiling is set by the cost of fuel oil and distillate, which can be substituted in electricity generation in times of short gas supply and which can help buffer gas price spikes. The implied range of gas prices that reflect this ceiling, however, is very broad—roughly $7–$12/MMBtu by 2010. EPRI's view is that the price floor for natural gas is set by coal, which has also experienced recent price increases, largely because of rising production costs and tight rail capacity. Assuming that coal prices remain relatively steady near today's levels, the implied floor price for natural gas would be in the range of $5.5–$6/MMBtu for the foreseeable future. Analysts suggest that the gas market will remain quite tight until more LNG terminals come on-line and until the global supply of LNG builds up sufficiently to meet growing demand in the United States, Europe, and Asia.

The other key uncertainty—the cost of CO_2 emissions controls or credits—will ultimately be determined by the target concentration of CO_2 in the atmosphere and the policies chosen to achieve this target. To date, trading in so-called carbon financial instruments has produced a wide range of prices, from less than $2/metric ton of CO_2 (tCO_2) on the Chicago Climate Exchange (a voluntary U.S. market) to more than $20/$tCO_2$ on the European Climate Exchange (a mandatory market), with high volatility. Looking further into the future, a recent EPRI study concluded that, assuming modest new technology development, the cost of CO_2 emissions by 2050 could range from less than $10/$tCO_2$ for an atmospheric concentration target of 650 ppm to more than $125/$tCO_2$ for 450 ppm, if economically efficient climate policies were implemented globally.

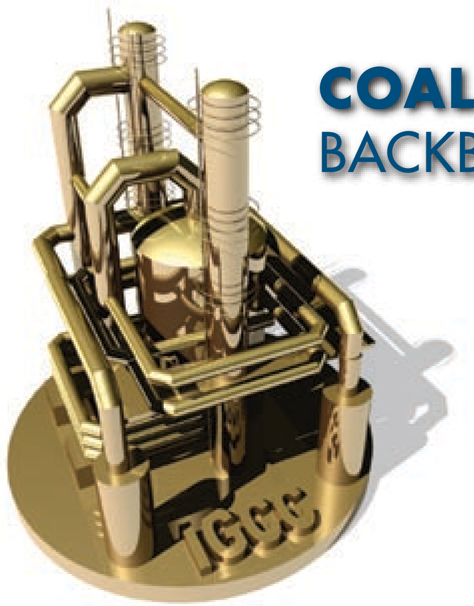
Electrification and Technology Choice

In the face of such uncertainties, one trend remains clear: electricity is likely to account for a steadily increasing share of overall energy demand. The reason is that a shift from direct consumption of fuels to electricity end use provides the best opportunity to reduce carbon emissions, because the vast majority of low- or non-emitting energy technologies are associated with electricity. The carbon intensity of power generation in the United States has fallen by 10% over the past two decades because of the increased use of nuclear and wind power and a shift from coal to natural gas. For the future, a critical element of climate policy needs to be an acceleration of the trend toward electrification of the economy, coupled with a shift toward non-emitting generation technologies.

If carbon emissions are priced consistently across the economy, electrification—defined as the proportion of kWh electrical energy to total final energy—will increase more rapidly as greater carbon constraints are applied. Today, the U.S. electric power sector accounts for about 17% of final energy. An EPRI study indicates that in the absence of climate policy, electrification is expected to continue, reaching 37% by the end of the century. If there is a decision to stabilize concentrations of CO_2 globally at 550 ppm, we would expect the share of energy produced by electricity in the United States to be over 50% by the end of the century. In addition to offering more opportunities to introduce low- and non-emitting energy sources, the economies of scale and the fixed nature of generation facilities make the deployment of many carbon reduction technologies—such as capture and storage—at power plants cheaper than the application of those technologies to millions of small, dispersed emissions sources, such as vehicle engines and home furnaces.

Ultimately, the choice among available generation technologies will depend on a variety of factors, including resource locations, local preferences, and especially the comparative costs of electricity produced. Higher market prices for carbon credits, for example, will tend to favor nuclear and renewable resources relative to coal and natural gas. Conversely, the uncertainty about future gas prices is so great that the projected costs of power from a natural gas–combined-cycle (NGCC) plant in 2020 virtually bracket those of most other generating options. For a CO_2 credit price of \$30/tCO_2, for example, electricity from a baseload NGCC plant could be either the lowest-priced option, if natural gas sells for \$3/MMBtu, or the highest-priced option, if gas sells for \$7/MMBtu or more (in 2005 constant dollars).

Given such uncertainties, the best technology strategy is to develop a robust portfolio of power generation options that will provide decision makers in the future an ample opportunity to respond to changing economic conditions and take into account new knowledge about climate change. To enhance the breadth of response, such options can aim to take advantage of abundant resources (coal), offer long-term resource stability (nuclear), pursue potentially low-cost opportunities (gas), and open new energy frontiers (renewables).



COAL
BACKBONE OF U.S. ELECTRICITY SUPPLY

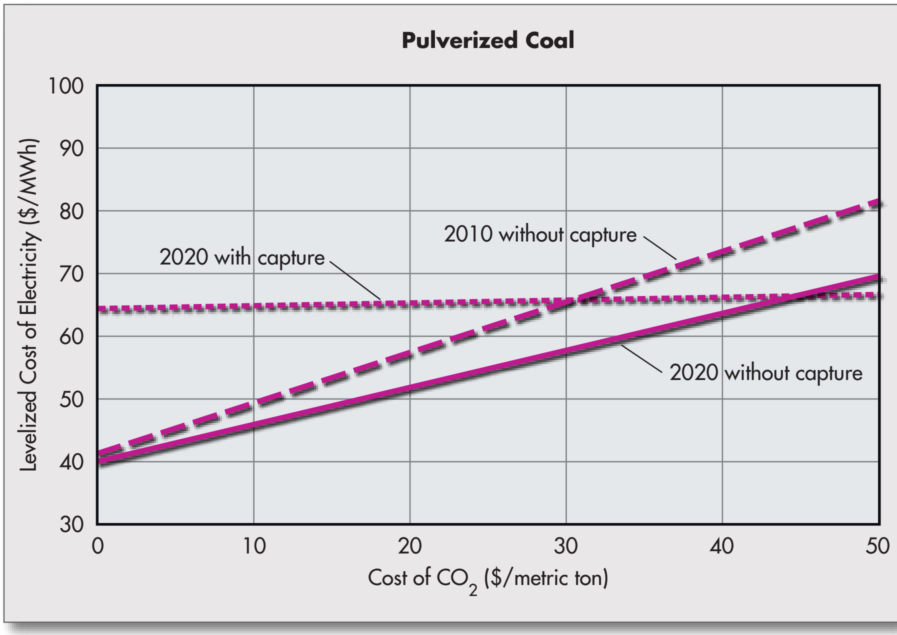
Coal currently accounts for more than half of the electricity generated in the United States and more than three-quarters of that generated in China. It is also the dominant fuel source for power production in India. Because coal is such an important resource in so many major economies, the development and deployment of affordable, efficient new coal technologies that produce less CO_2 is key to meeting targets for reducing CO_2 without risking global economic instability.

Direct Combustion Technologies

Most plants today use pulverized coal (PC) technology, in which the coal is finely ground, mixed with air, and blown into a boiler for efficient combustion. High-pressure steam produced in the boiler passes through a steam turbine, which drives an electric generator. The pressure and temperature of the steam produced in the boiler are often used as shorthand to characterize the design features of PC plants. Currently, the majority of coal-fired boilers in the United States are subcritical—meaning that the pressure and temperature are below the critical point of water. Subcritical plants are well established and relatively easy to control, with overall energy conversion efficiencies in the range of about 30% to almost 40% (calculated using the higher heating value of the coal).

Higher efficiencies can be achieved by increasing steam temperature and pressure to supercritical conditions. Some 400 supercritical coal-fired power plants are currently operating around the world, including a large fleet in the United States. To prevent premature wear, supercritical plants require careful control of water chemistry and metal temperatures, but today they are just as reliable as subcritical plants. To gain further efficiency, so-called ultra-supercritical (USC) plant designs have been introduced in Europe and Asia and are now being developed for the United States as well. Steam temperatures in initial USC units will be about 1100°F (600°C), with the goal for future designs being 1400°F (760°C) or higher, which translates to an energy conversion efficiency of approximately 50%. As USC plant designs cross the 1250°F (670°C) threshold, they will require more-expensive, nickel-based alloys for high-temperature components. A sustained commitment to materials technology development is needed to produce these advanced alloys, address field fabrication and repair issues, gain approval from industry standards organizations and insurers, and optimize plant designs for their use.

Developmental advances are also under way for two other direct combustion technologies. Circulating fluidized-bed (CFB) systems are already being selected for new generation capacity, especially where inexpensive, hard-to-burn fuels such as lignite and solid waste are available. CFB plants operate at relatively low temperatures and thus produce less nitrogen oxide pollutants (NO_x) in the boiler than PC plants, avoiding the need for catalytic postcombustion



The cost of electricity generated from fossil fuels will be affected strongly by whether mandatory carbon constraints are enacted and if so, how expensive it will be to comply. Pulverized coal, long a cost leader, will become quite an expensive option if CO_2 emission costs are high, even with the coming decade's technology improvements. The addition of carbon capture technology will become the more economic choice when CO_2 prices surpass $45/metric ton.

controls. In addition, the aerodynamically suspended "bed" of a CFB boiler is fed with a sorbent (usually limestone particles) to remove sulfur dioxide (SO_2) pollutants. This approach produces a bit more CO_2, however, which puts CFB technology at a disadvantage relative to PC plants under stringent carbon emissions constraints.

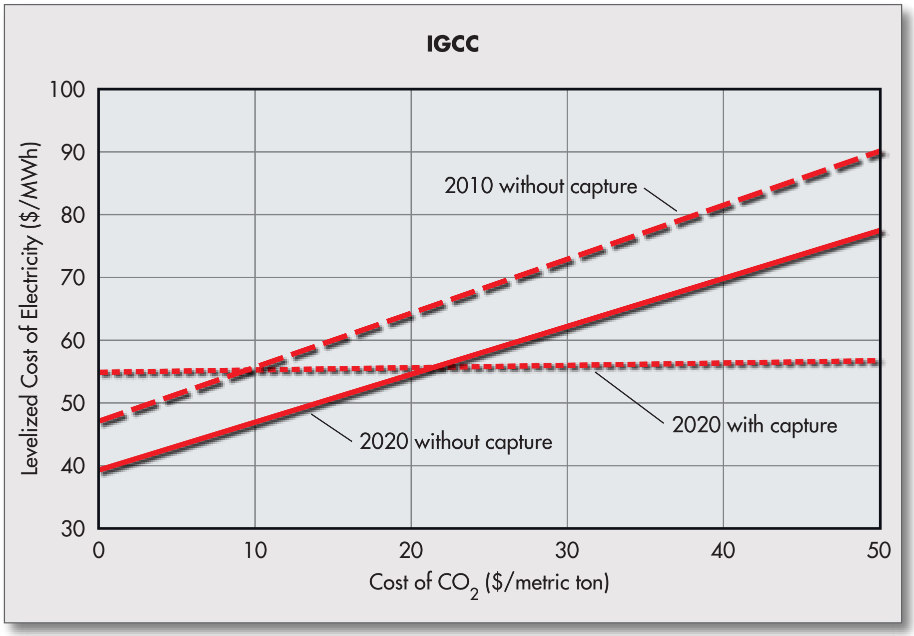
Now oxy-combustion—the burning of pulverized coal in pure oxygen separated from air—has emerged as a potential combustion option for the future. The resultant flue gas has a high CO_2 concentration, mixed with water vapor, particulates, residual oxygen, and SO_2. This alternative is attracting increased attention because the high-concentration CO_2 stream would be more amenable to separation for long-term storage. Advances in systems that can properly manage oxygen combustion and CO_2 recycling and purification will require additional development work before full-scale demonstration, and new methods of oxygen production may be needed to make oxy-combustion technology economical.

Integrated Gasification–Combined-Cycle (IGCC) Systems

In the IGCC process, coal reacts with oxygen and steam under high temperature and pressure to form a combustible gas composed mainly of hydrogen and carbon monoxide. This "synthesis gas" is cooled, cleaned, and fired in a gas turbine. In a combined (gas and steam) cycle, the hot exhaust from the gas turbine passes though a heat recovery steam generator, which produces steam that drives a second turbine. Because of the heat recovery, IGCC plants can operate at efficiencies approaching 45%. Use of nitrogen diluents in the gas turbine combustor limits NO_x production to about 10 ppm. SO_2 emissions are low as well because of sulfur removal rates greater than 99% during synthesis gas cleaning prior to combustion. IGCC has the added advantage of being amenable to the addition of what is known as a water shift reactor downstream of the gasifier to produce a synthesis gas with mostly hydrogen and CO_2. Commercial processes from the chemical industry can remove CO_2 more economically in this relatively concentrated, high-pressure form than they can remove it from a diffuse flue gas stream at ambient pressure, such as occurs in pulverized-coal (PC) boilers.

The basic IGCC concept was first successfully demonstrated at commercial scale at EPRI's pioneering Cool Water Project, in Southern California, from 1984 to 1989. There are currently two operating coal-based IGCC plants in the United States and two in Europe. The two U.S. projects were supported initially under the Department of Energy's Clean Coal Technology demonstration program but are now operating commercially without DOE support. Because of this experience, IGCC has moved from the demonstration phase to a commercial technology, currently offered by several supplier teams. Although several power generators have announced plans to build IGCC units and have contracted with supplier teams for engineering studies, no plants have yet been built under this new market regime.

While DOE's Clean Coal program concentrates on research, development, and demonstration of promising new coal technologies, EPRI has organized the CoalFleet for Tomorrow initiative to help speed their commercial deployment. This collaborative program involves power generators, equipment suppliers, the government, and other industry stakeholders. CoalFleet focuses on incorporating user-defined requirements and lessons learned from existing IGCC plants into new designs; it is actively working with the power companies now conducting engineering studies. In particular, CoalFleet aims to optimize the technology at a scale matched to state-of-the-art gas turbines, which are now being offered for operation on synthesis gas. In North America and other areas with 60-Hz power grids, this corresponds to an approximately 600-MW two-train plant using FB-class gas turbines. The size of a gasifier–gas turbine train will be larger in Europe, Australia, most of Asia, and other areas that operate on 50-Hz power grids. IGCC train sizes in both



Integrated gasification–combined-cycle systems also become expensive when CO_2 costs rise. However, because carbon is easier to remove from the gasification stream than from pulverized-coal flue gas, the addition of carbon capture technology pays off much earlier for IGCC—at around \$20/metric ton of CO_2.

50-Hz and 60-Hz areas will be larger when the more-advanced G-class and H-class gas turbines are introduced. CoalFleet has also identified opportunities to reduce the cost of IGCC through improvements in industry design requirement consistency, efficiency, gasifier reliability, materials handling, and gas separation systems.

Electricity from the first group of U.S. IGCC plants is expected to cost about 15–20% more than that from conventional PC units with SO_2 and NO_x controls, assuming no requirements for carbon capture. Through active product development by the equipment suppliers, this cost differential may be reduced or eliminated, at least for high-rank coals. For low-rank coals, particularly lignite, further design improvements will be needed to make IGCC more competitive. For any fossil fuel, the cost of IGCC and of competing coal technologies increases substantially if CO_2 capture and storage are required. The incremental cost penalty for removing CO_2 from synthesis gas in an IGCC plant is less than that for removal from the flue gas of a PC plant, but fuel- and site-specific individual cost analyses must be made in order to compare overall plant economics.

Carbon Capture and Storage

Many component technologies for carbon capture and storage (CCS) have already been developed, but both the size and number of demonstration projects are very small with respect to the scale that will be necessary to mitigate significant future CO_2 emissions. In addition, long-term retention of stored CO_2 will require approval of monitoring techniques and standards at various governmental levels and acceptance by insurers. Another major consideration is the highly diverse nature of potential storage sites, which differ widely in their geologic characteristics, potential for economic co-benefits, and geographic distribution.

The first step in the CCS process is removal of CO_2 from either IGCC synthesis or combustion exhaust gases. Relatively small-scale CO_2 separation systems are commercially available today and are serving the industrial market for CO_2, but major improvements in the cost, performance, and operating characteristics will be needed before the large systems required for power plant CO_2 capture can be widely deployed. Among emerging options for large-scale CO_2 removal are new chemical solvents, alternative physical/chemical separation methods, novel systems based on mineralization processes, and concentration of CO_2 in flue gas via high-oxygen combustion or chemical looping. EPRI is currently evaluating these options and intends to develop appropriate-scale projects to speed the validation and deployment of promising technologies and to improve the economics of their integration with coal power plants.

One particularly promising new CO_2 capture technology is the chilled-ammonia process. The current monoethanolamine (MEA) process for removing CO_2 from the flue gas of a PC plant has several disadvantages, including low CO_2 loading capacity of the absorbent materials and high energy consumption during absorbent regeneration. The chilled-ammonia process increases loading capacity at lower temperatures by using high concentrations of ammonium carbonate absorbent, then saves energy by regenerating the absorbent at high pressure. Early data from laboratory-scale equipment indicate that removing CO_2 from a PC plant using the chilled-ammonia process may reduce electricity output by only 10%, compared with 29% for the MEA process. Because of these promising early results, EPRI is working with Alstom to build a 5-MW chilled-ammonia pilot test facility, expected to begin operation in 2007 and provide capture test results in 2008. A CO_2 storage test could follow in 2009.

Transportation of CO_2 from the point of capture to the point of geologic injection for storage poses fewer technical unknowns, with dedicated CO_2 pipelines already commercially established, but it appears there may be deployment barriers in siting issues and the sheer scale of the major new pipeline networks that will be necessary to carry compressed CO_2 from power plants to injection wellhead locations.

A number of deep, leak-proof geologic formations have been identified as candidates for long-term CO_2 storage. These include depleted oil and gas reservoirs, deep saline formations, and unmineable coal seams. In most cases, CO_2 would be injected into such formations as a supercritical fluid to maximize the storage density. To ensure that injected CO_2 would remain in this state, the geologic storage formations would have to be at depths greater than 800 meters (about half a mile) below the earth's surface. The effectiveness of such formations for long-term CO_2 storage is the subject of much international research and many testing programs. Given that power plants are widely dispersed geographically, deep saline formations—which tend to be very large and relatively abundant—will be important reservoirs for CO_2 wherever they can be put to no other beneficial use (such as enhanced oil and gas recovery or injection for coalbed methane production).

Other issues will also have to be resolved before CO_2 storage can make a major contribution to reducing atmospheric concentrations. New regulations for site permits will be needed, together with resolution of legal liability issues, especially for injections not associated with enhanced oil and gas recovery. Public acceptance will be crucial; potential risks to human health or to ecological systems, and associated mitigation measures, must be quantified and communicated. EPRI is working to resolve these technical and institutional issues and participates in several DOE regional pilot-scale studies to evaluate various approaches to storage.

NUCLEAR POWER
CHALLENGES AND OPPORTUNITIES

As the most widely deployed carbon-free technology, nuclear power will play a critical role in stabilizing atmospheric CO_2 levels. There are currently about 440 nuclear power plants operating in 31 countries, generating about 17% of the world's electricity. More than two dozen additional reactors are under construction around the world. In the United States, 103 reactors are now operational, almost twice the number operating in any other country. The safety, reliability, and economic performance of the fleet have steadily improved over the past 20 years, making these reactors a valuable asset. Given their performance, the lessons learned and applied to new designs, and the need for emission-free generation of electricity, many U.S. utility companies are looking hard at new nuclear plants as part of their future generating mix. EPRI is supporting nuclear industry activities to begin building new nuclear plants in the United States before the end of this decade.

These activities focus on Generation III+ advanced light water reactors (ALWRs) with standardized designs certified by the U.S. Nuclear Regulatory Commission (NRC) and now available for new orders. Plants based on these new designs have already been constructed on schedule in Japan and South Korea. No major technical hurdles stand in the way of ALWR orders in the United States, and passage of the Energy Policy Act of 2005 has gone a long way toward reducing financing uncertainties. Standardization has helped reduce costs significantly since the previous-generation nuclear plants were built, and the new designs incorporate the latest safety and reliability features—some including passive safety measures—which are based on decades of research.

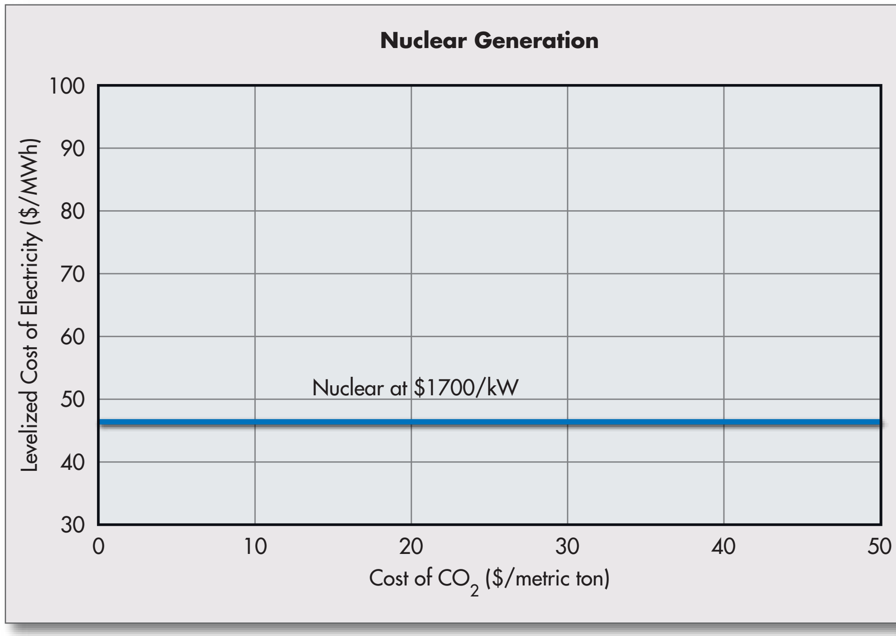
Near-Term Activities

In 2002, to reduce regulatory uncertainty, DOE announced a cost-sharing program—Nuclear Power 2010—to test and demonstrate the new NRC regulatory process, 10CFR Part 52. The new three-part licensing process requires design and siting decisions and other key approvals before construction of a nuclear plant begins. Included in the NP2010 program are projects to complete and submit three Early Site Permit (ESP) applications and a number of combined Construction and Operating License (COL) applications.

The ESP allows a utility to "bank" an approved site for a 20-year period, and the COL pairs a site with a specific certified design prior to construction. Significant time and cost are associated with application and NRC staff review under this Part 52 process; and the last step—the COL—is unproven and a significant source of uncertainty and business risk.

In addition, NP2010 will fund the first-of-a-kind engineering necessary to reduce the cost premium usually expected in initial construction of plants with new designs. EPRI is providing the industry with R&D support related to detailed engineering and construction of the proposed reactors and is working with the Nuclear Energy Institute on resolving technical issues and standardizing the form and content of licensing submittals.

Meanwhile, renewal of licenses for existing plants continues to make steady progress. In addition to 42 applications completed and 9 under review, the commission has received letters of intent for 27 additional renewal applications to be submitted from July 2006 to early 2015. The total is 78. Consequently, EPRI—working closely with other industry organizations—is currently focused on helping utilities meet the inspection and surveillance commitments required for the granting of 20-year license renewals from the NRC.



Because nuclear generation produces no carbon emissions, its power production costs are not affected by carbon constraints. But no new U.S. nuclear plants have been ordered in over 30 years, and deploying a new fleet of advanced plants carries a number of uncertainties. If the next generation of nuclear plants can be built for $1700–$1800/kW, they will be very cost-competitive.

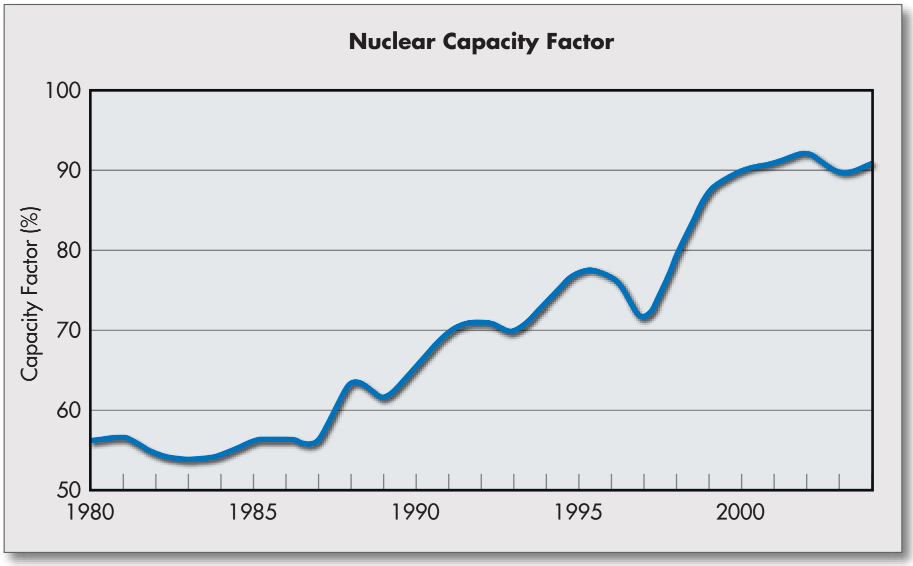
Mid-Range Concerns

Beyond consideration of new plant construction, a variety of mid-range concerns will have to be resolved if nuclear power is to take its place among the primary non-emitting electricity generation options for the long term. Perhaps foremost among these is resolution of the U.S. high-level nuclear waste issues. Although an operational spent-fuel repository is not a requirement for new plant construction, state and federal governments—as well as potential investors in new reactors—need confidence that a workable and sustainable spent-fuel management scheme can be put in place. Current efforts by DOE and industry leaders are converging on such a sustainable approach, which includes a centralized interim storage of spent fuel in the very near term, continued progress toward licensing and construction of a permanent spent-fuel repository at Yucca Mountain, Nevada, and ultimate deployment of a proliferation-resistant closed fuel cycle. The first step, centralized interim storage, while not a condition of new plant construction, would clearly erase a major impediment.

A major financial concern had been renewal of the Price-Anderson Act, which provides for the nuclear industry's self-funded liability insurance. The provisions of this legislation are considered by many executives to be a prerequisite for new nuclear plant orders. The recent passage and signing of the Energy Policy Act of 2005 provided for continuation of these critical self-insurance provisions.

Because of the long gap in nuclear plant construction in the United States, domestic component fabrication and manufacturing capability has declined. In addition, competition will be stiff among construction industries for qualified workers to build new plants, particularly nuclear-qualified welders and inspectors. The addition of significant nuclear capacity will also create demand for more reactor operators and maintenance staff, as well as for nuclear engineers, particularly since many experienced personnel currently in the workforce will be retiring in the next few years. To prepare for these needs, utilities, vendors, industry associations, and the government have focused in recent years on replacement staff education and training, for both engineers and technicians, and progress is evident.

Assuming that these and more immediate licensing concerns can be adequately addressed, COL applications are likely to come in the 2007–2008 timeframe, with actual plant orders following in 2008–2010. Currently there are four new reactor designs certified by the NRC: the Westinghouse System 80+, the General Electric Advanced Boiling Water Reactor, the Westinghouse AP600, and—most recently certified—the Westinghouse AP1000. Two others—General Electric's Economic Simplified Boiling Water Reactor (ESBWR) and Areva's U.S. Evolutionary Pressurized Water Reactor (USEPR)—are now undergoing the certification process. All six of the ALWR designs currently certified or in the certification process already meet or are addressing the comprehensive set of design specifications that are put forth in the EPRI Utility Requirements Document.



Nuclear plant performance has improved dramatically since the 1980s, with annual capacity factors for the last five years averaging about 90%. Such operational excellence has made nuclear a low-cost leader in power production.

Long-Term Opportunities

The nuclear industry is working to add significant new capacity in the United States by about 2020; a recent EPRI study concludes that this will be possible if gas prices remain above about $4.75/MMBtu or if the capital costs of new nuclear plants can be reduced by 10%. Most of the new capacity is expected to come from Generation III+ reactors, especially from ALWR designs optimized to offer enhanced economics for near-term deployment. For the longer term, however, a new group of nuclear technologies, Generation IV, is being pursued by government entities with hopes of addressing new missions and long-term sustainability. Generation IV technology would be deployed between 2020 and 2030.

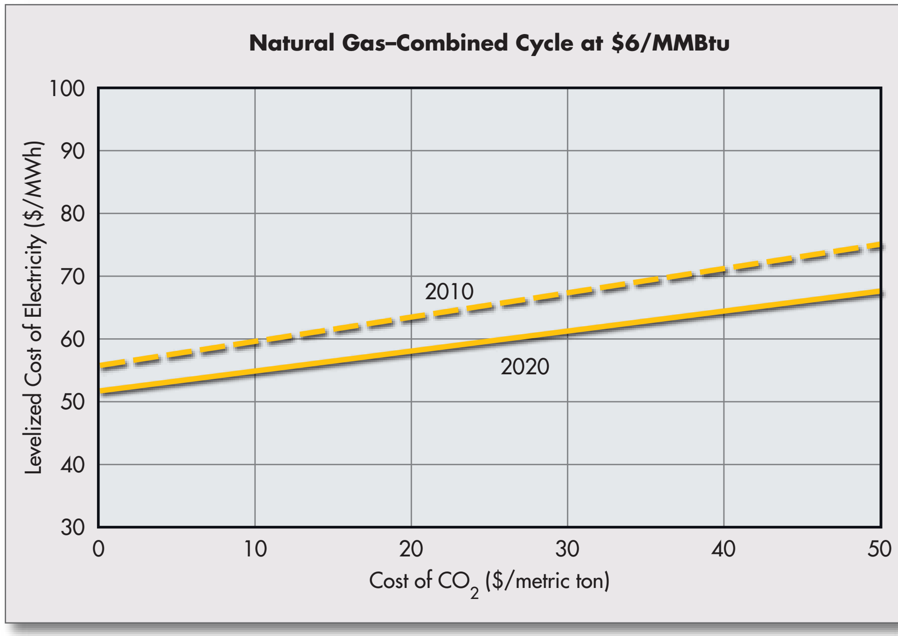
Development of this next generation of nuclear systems is being approached through an international R&D program involving ten individual countries plus the European Atomic Energy Community. Work so far has identified a number of promising technologies, and research continues through DOE, U.S. national laboratories, and private companies. One technology of particular interest is the very-high-temperature reactor (VHTR)—a helium-cooled reactor that would operate at around 900–1000°C and would have the ability to produce hydrogen.

NATURAL GAS
UNCERTAINTY IN PRICE AND SUPPLY

As a fuel for electricity generation, natural gas recovered from tight restrictions on new capacity in the 1970s to account for almost 95% of new capacity in 2000. Since then, however, overbuilding and higher gas prices have led to a sharp contraction of new orders and steep decline in capacity factors at existing plants—from roughly 50% in 2001 to less than 30% in 2005. Unit flexibility for meeting shorter-term peak loads and environmental compliance are currently the main drivers for utilization of gas-fired plants. Despite the recent price-driven hiatus, EIA expects natural gas to retain its relative cost advantage in the near future and to account for about 40% of new capacity additions between now and 2030, assuming no mandatory carbon constraints are imposed. If these assumptions are borne out, natural gas's share of total electricity generation will be 17% in 2030, compared with 18% in 2004. Natural gas consumption in the electric power sector is projected to peak in 2019 and then start to decline as new coal-fired generation increasingly displaces gas-fired technology.

Being able to keep up with overall rising demand will require technological innovations all along the natural gas value chain, from production to combustion. In particular, with conventional gas production continuing to decline in the lower 48 states, both onshore and offshore, new resources will have to be opened. So-called unconventional domestic gas production will have to be increased, as will imports of gas as LNG. In addition, changes in power generation technologies will play a key role in determining how long natural gas remains the low-cost leader.

The recent run-up in natural gas prices provides a golden opportunity to use advanced technology to open new gas resources. According to EIA, the rapid development of new exploration and production technologies could reduce wellhead prices of natural gas in the lower 48 states by as much as 19%, compared with a slow-development scenario. A major specific impact of such technology development would be to make certain types of currently hard-to-exploit gas resources—such as tight sands, Devonian shale, and coalbed methane—more accessible. As a result, EIA expects unconventional resources to account for 45% of total natural gas production in the continental United States by 2030.



Because they burn a cleaner fuel, natural gas–combined-cycle plants suffer less under carbon constraints than do coal-based technologies, and they are expected to reduce electricity costs by perhaps 10% by 2020 through efficiency improvements. Still, NGCC plants are vulnerable to increases is natural gas prices, which may very well remain volatile in the coming decades.

Importing LNG

One of the great ironies of the current efforts to reduce CO_2 emissions from fossil fuel use is that much of the natural gas released as part of petroleum production in remote areas of the world is simply flared—burned in the open air without capturing any of its energy value. The most cost-effective way to exploit such an otherwise stranded natural gas resource is to build a pipeline to a marine terminal, liquefy the gas, transport it by tanker to a port equipped to accept LNG, and there feed it into a major pipeline. Up to now, only four LNG terminals have been operating in the United States, all at modest scale. With U.S. gas prices expected to remain high and more countries wanting to find new ways to export natural gas, however, EIA forecasts U.S. imports of LNG will increase more than sixfold by 2030, surpassing natural gas imports from Canada as early as 2010. EPRI estimates are even higher, suggesting that, by 2010, U.S. imports will exceed the requirements of either Europe or Asia, which have dominated the LNG trade up to this point.

LNG is produced when natural gas is cooled to about –260°F (–161°C) at atmospheric pressure. Liquefaction reduces the volume approximately 600-fold, facilitating high energy storage density. To keep LNG cold, it is transported in insulated, double-walled tanks at atmospheric pressure. The liquefaction and transport of LNG has become cheaper than shipping gas through offshore pipelines over distances greater than about 700 miles (1100 km) or through onshore pipelines over distances greater than about 2200 miles (3500 km). These figures are very rough, however, because of local factors. Transportation of LNG by truck, for example, is quite limited within the United States, which has a vast network of gas pipelines, but is more common in countries where there is no national pipeline grid. Over the past 20 years, the overall cost of LNG production and transport has fallen by about 30%, so that use of this technology now adds only about $1.80/MMBtu to the cost of the basic feedstock.

Although the technologies for liquefying, storing, transporting, and vaporizing LNG are well established, their more widespread deployment in the United States faces several hurdles. Not the least of these is public concern over safety. However, it should be noted that worldwide there are currently 17 LNG export (liquefaction) terminals, 40 import (re-gasification) terminals, 136 LNG ships, and about 200 peak-shaving and LNG storage facilities—operating with what a study by the Institute for Energy Law & Enterprise of the University of Houston Law Center calls "an enviable safety record."

Introducing New Generation Technologies

Although most of the recent expansion of natural gas use for electricity generation has involved large gas turbines (often paired with steam turbines in combined-cycle configurations), future growth will depend in part on the successful introduction of new generating technologies, both large and small. Today's NGCC plants can have outputs of over 500 MW and overall efficiencies surpassing 50% (calculated using the lower heating value of natural gas), compared with 35–44% for today's simple-cycle gas turbine plants—the workhorse for peaking capacity. Further improvements are expected. By 2020, an NGCC plant should have an overall operating efficiency of over 55%. Such a plant would produce about half the CO_2 emissions of today's coal plants without carbon capture.

Meanwhile, a variety of smaller, gas-based generation technologies are starting to become more popular. Microturbines, for example, were commercially introduced in 2000 and are now either available or being developed in the 30–350-kW capacity range. They are considered ideal for distributed generation applications because of their flexibility in connection methods, their ability to be stacked in parallel to serve larger loads, and their improved reliability. Typical applications include supplying either stand-alone or backup power for customers ranging from financial services and data processors to hospitals and office buildings. Most microturbines feature an internal heat exchanger, called a recuperator, which increases efficiency by preheating inlet air. An additional heat exchanger can be added for combined heat and power applications.

Fuel cells, which substitute an electrochemical process for direct combustion of fuel, potentially offer very high efficiency and low emissions in their use of natural gas. About 200 units of the first commercially available 200-kW phosphoric acid fuel cell are now in service worldwide, often providing on-site premium power for sensitive operations, such as credit card processing. At the same time, research is under way to develop a hybrid generation technology in the 1–20-MW range combining small gas turbines and solid oxide fuel cells (which operate at higher temperatures than phosphoric acid cells); this approach could potentially offer electric service providers their highest-efficiency generating option.

Another very efficient way to use natural gas is in combined heat and power (CHP) applications, where the thermal exhaust from a microturbine or fuel cell is used to provide heat for an industrial or commercial facility. Some electric utilities are entering the CHP market as a new business opportunity: the installation of a CHP unit at a customer's site can help provide load relief during critical peak hours, defer larger capital expenditures on feeder line upgrades, and (if the utility retains ownership) offer a dependable revenue stream from a generating unit with a high overall energy efficiency.

RENEWABLE ENERGY
IMPROVING PERFORMANCE AND COST

When commercial interest in renewable energy resources peaked after the oil shocks of the 1970s, the results included some interesting technology developments but generally poor financial returns for early investors. The decline of oil and gas prices during the 1980s made it even more difficult for emerging renewable energy technologies to compete in any but niche applications. Now that fossil fuel prices have again risen sharply and concerns over global climate change and energy security have grown, interest in renewables is on the upswing once more. Today investments in renewable energy are more firmly market based and are supported by a more solid regulatory and technological foundation. Several renewable resources have become economically appealing in their own right, and the groundswell to adopt constraints on carbon emissions may continue to improve their competitive position with respect to fossil fuels.

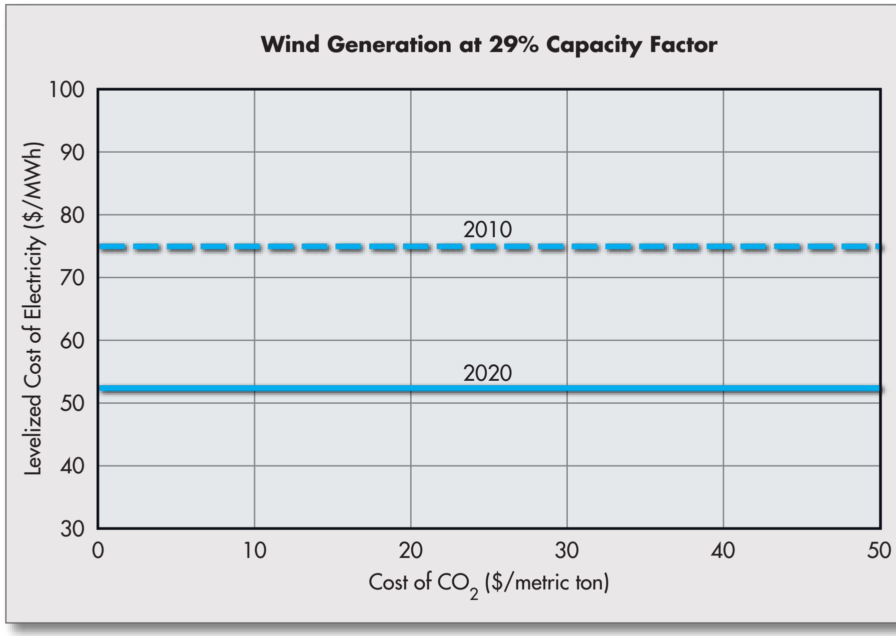
Renewable energy resources such as solar and wind energy have a number of very favorable aspects: they are clean, their supply is not depleted over time, and they are—at least from a fuel standpoint—free. In response to the high global demand resulting from government mandates for renewable energy, installation of wind and solar photovoltaic generation is proceeding at a rapid pace worldwide, growing at 20% to 30% per year. Because the demand for wind turbine equipment and services exceeds the available supply and the supply of pure silicon for solar photovoltaic (PV) cells is limited, wind and solar PV have experienced a 10% to 30% increase in installed costs since 2004. However, the wind and solar PV industries are expanding manufacturing capabilities and continue to improve the performance of their products, which will ultimately lead to further reductions of both the installed cost and the cost of electricity.

Although renewable energy capacity is

growing rapidly, renewable energy's contribution to total primary energy and electricity generation in the United States is still very small. EIA data show that in 2004, renewable energy contributed about 9% of total U.S. electricity, which included 6.8% from hydro, 1.5% from biomass, 0.4% each from geothermal and wind, and only 0.02% from solar thermal and photovoltaic generation.

Several challenges must be addressed in order to develop non-hydro renewable energy to the point that it contributes a significant portion of total electricity generation. The challenges include the relative newness of the industry; the diffuse nature of the wind, solar, biomass, ocean, and other renewable resources; and the intermittency of most of the resources—especially wind. However, the industry is actively developing new technology to address these issues by improving efficiency to capture the diffuse energy and employing energy storage technology and power electronics to address intermittency. This technology push, combined with a strong market pull, suggests that installation of new renewable energy generation can be sustained at a high rate and that the relative contribution of renewable energy will grow substantially in the future.

Wind power has made great strides over the last decade. Wind is generally the most affordable renewable energy resource, with costs now low enough for it to compete directly with conventional generation in many parts of the United States. But intermittency continues to challenge the integration of wind farms with power grids. Solar PV systems are still generally too expensive to serve as a wholesale generation option but can compete at the retail level in numerous customer-centered applications. Biomass shows promise for expansion in two distinct areas—direct firing in power plants and conversion to liquid or gaseous biofuels. Ocean energy (wave and tidal) is gaining interest worldwide as small-scale units are being put in service or evaluated. Overall, the currently small amount of power generation from non-hydro renewables is expected to more than double over the next 20 years, with biomass and wind dominating new capacity additions. The ultimate importance of these renewable energy resources, however, will depend heavily on the ability of new technologies to improve in performance and cost.



Since wind generation creates no carbon emissions, it will not be impacted by carbon constraints. The average capacity factor for the current fleet of U.S. wind machines is about 29%, with the top-performing sites weighing in at about 43%. Better forecasting, better grid integration, and technology improvements will substantially reduce wind energy costs in coming years. Capacity factors may also be improved by exploiting the higher wind regimes available to offshore installations.

Integrating Wind Into the Grid

The installed capacity of wind generation in the United States and Europe has been growing at more than 20% per year, primarily as the result of an 80% decrease in the cost of electricity from utility-scale wind systems during the last two decades, the federal Production Tax Credit in the United States, and favorable tariffs for renewable energy in Europe. The current competitiveness of wind has stemmed largely from recent advances in turbine design, including greatly increased size and efficiency. Leading the way has been a tenfold increase in rotor diameter, from 10 meters on a 25-kW turbine in the 1980s to more than 100 meters on the 3.6-MW turbines now being offered for offshore applications. Increasing the height of support towers to reach higher wind speeds aloft has increased the annual capacity factor of wind machines at sites having low and moderate wind speeds.

Nevertheless, improvements are needed to compensate for the intermittency of wind energy over the timescales most critical to power system planning and operation. In the seconds-to-minutes timeframe involved in regulating system frequency, extra costs can be incurred if conventional generators must be used to compensate for intermittency, or if other special equipment such as static VAR compensators are needed to respond to momentary disturbances caused by wind gusts or lulls or by turbine trips from system faults. A better approach combines a number of technologies: advanced turbine designs that employ cutting-edge power electronics for variable-speed operation, power factor control, and low-voltage ride-through capability;

static and dynamic VAR-control devices installed between the wind plant and the electricity grid; and advanced energy storage options, ranging from ultracapacitors to high-cycling batteries. Such options promise to provide a more forgiving interface between wind turbines and the utility power grid. Hawaiian Electric Power Company is testing an "electronic shock absorber" device of this sort near a new wind project on the Big Island of Hawaii.

Changes in wind generation output on a minute-to-hour timescale are problematic because they may require a system operator to ramp load-following generation units up or down in response. For these fluctuations, wind generation can be integrated with existing conventional and pumped-storage hydro capacity to smooth wind energy by absorbing excess during periods of low demand and releasing it back onto the grid during periods of high demand. In 2004, the Bonneville Power Administration began testing two BPA wind integration services to assist wind plant operators and wind energy customers in this way.

The largest cost associated with integration usually results when day-ahead forecasts of wind generation turn out to be inaccurate, forcing a grid operator to reschedule more expensive generating units. In 2005, EPRI and the California Energy Commission completed research on wind energy forecast algorithms that show promise for forecasting both same-day and next-day ramp rates more accurately.

Altogether, the ancillary costs associated with integration problems range from less than \$2/MWh up to about \$10/MWh, depending on the degree of wind penetration in the generation mix and on specific system characteristics. For comparison, the cost of wind energy itself is now roughly \$50/MWh without a production tax credit.

Finding New Niches for Solar PV

PV cells convert solar energy to electricity directly, at about 15% efficiency in a typical commercial unit. Given the relatively high cost of the crystalline silicon in most of today's PV units, their use has generally been restricted to niche markets—particularly in applications for which power from a grid is unavailable. However, the combined size of these niche markets, government incentives for grid-connected customers in states such as California, and the 30% federal solar tax credit enacted in the 2005 Energy Policy Act have become substantial enough to stimulate something of a building boom in manufacturing facilities that specialize in making the silicon wafers used in PV arrays. In addition, research is producing new, lower-cost alternatives to crystalline silicon as PV material, and innovative approaches to metering are helping open additional market niches.

Under U.S. law, utilities must allow customer-owned systems to be connected to their lines and must purchase the excess electricity these systems generate. Most PV installations with net metering have in the past been at commercial and industrial facilities, but declining costs have led to their increasing use in the residential sector. DOE reports that studies of net metering reveal several benefits to utilities, including reduction in peak demand, increased system reliability, and avoided cost of building new power plants.

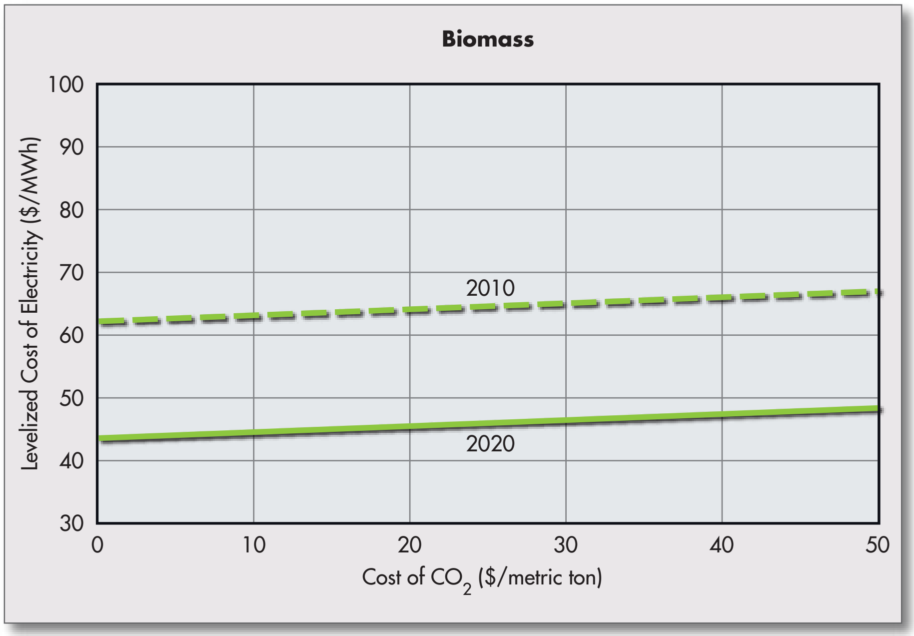
Research into new PV materials is pointing to at least two ways in which the cost of PV systems may be substantially reduced in a few years. One approach is to make the production of silicon PV cells more efficient by pulling continuous ribbons of crystalline silicon, rather than sawing and etching conventional wafers. The other approach is to use thin films of PV material, either silicon or alternative semiconductors, such as gallium arsenide. A big advantage of thin films is that they can be built directly into roofing materials rather than installed as a separate module on top. A major problem with thin-film systems has been their relatively low conversion efficiency, but this gap is rapidly being closed. Shell Solar, for example, recently claimed a record 13.5% conversion efficiency for its thin-film CIS (copper-indium-diselenide) photovoltaic technology, which the company believes could reduce the cost of solar panels by more than 50% by 2012, according to a report in the *Economist.*

Biomass for Power and Fuel

Biomass-based power generation is deemed to yield little or no net emissions of CO_2 because of the sequestration effect associated with a sustained cycle of planting and harvesting. In other words, the CO_2 emitted during combustion of a biomass fuel is reabsorbed by plants being grown to provide the next batch of fuel. Although biomass is the largest non-hydro renewable source of electricity in the United States, the vast majority of this power is generated in industrial CHP applications, especially in the pulp and paper industry, where process by-products provide the fuel.

Electric utilities also burn some biomass in their power plants, but usually in combination with other fuels, particularly coal. The main impediment to wider use of biomass in the electric power industry has been the cost of obtaining feedstock. That cost may fall, however, with the introduction of fast-growing crops raised just for their biomass. The use of such crops for power generation—including biomass integrated gasification–combined-cycle technology—is currently being developed with DOE sponsorship.

Meanwhile, liquid biofuels may provide a more realistic alternative to the so-called hydrogen economy when it comes to providing primary energy to fuel cells in vehicles and stationary applications. Ethanol from grain crops, of course, has long been used as an additive to gasoline, but now methanol derived from gasification of woody biomass is competing with pure hydrogen for use in proton exchange membrane (PEM) fuel cells. The distinguishing characteristic of PEM units is that they operate at lower temperatures than most other fuel cells, as well as having lower weight and volume. As a result, they are expected to be more suitable for vehicular applications. The first fuel cell car



Biomass-based power generation is considered to produce little or no net CO_2 emissions because the CO_2 emitted during combustion is reabsorbed by plants being grown in the subsequent biofuel crop. The development of faster-growing crops is expected to improve the economics for both solid combustion feedstock and liquid biofuels such as methanol.

using methanol rather than pure hydrogen was introduced in 2000 by DaimlerChrysler, and now several other manufacturers have brought out competing models. One advantage of using methanol is that it has a higher energy density than pure hydrogen, so that vehicles can travel farther between fuel refills. In addition, because methanol is a liquid at room temperature, it would fit better into the existing fuel delivery infrastructure than either highly compressed or highly chilled hydrogen.

Although much of the discussion about PEM fuel cells has focused on their suitability for vehicles, they may in fact find widespread use in distributed stationary applications as well, given favorable economic conditions. In stationary units, they can also be fueled by natural gas. Either way, the ability of a customer to use a PEM fuel cell to run relatively small electrical loads (50–75 kW) or to sell power to a utility grid during peak hours with net metering could open a whole new set of business opportunities and challenges for the utilities involved.

Other Renewables

In addition to the technologies just discussed, other renewable resources may play an increasing role in providing electricity in the future if economic conditions are right and if ongoing technology development is successful. Solar thermal plants and geothermal resources, for example, already have major facilities in operation.

Solar thermal plants based on concentrating solar power (CSP) have been operated for several years and appear attractive for application in areas with high direct insolation, such as Australia and the desert Southwest in the United States. Three types of CSP plants are currently in use. Parabolic trough systems use single-axis, rotating trough-shaped mirrors to track the sun and concentrate its energy on long, oil-filled cylindrical receivers; such trough systems now appear to represent the least expensive, most reliable CSP technology for near-term applications. Power tower facilities use two-axis flat reflectors to track the sun and focus its energy on a receiver mounted on top of a tower; this system's molten salt working fluid provides enough storage capacity to make the system more dispatchable from the standpoint of grid integration. Parabolic dish engines use numerous individual concentrators with heat engine generators at their focal points, which produce a few kilowatts of electricity apiece; parabolic dish engines are currently in the prototype phase of development, and two manufacturers are planning commercial installations in California.

Although potential geothermal energy sites are particularly limited geographically, they represent a highly valuable resource where available. Unfortunately, overproduction at the world's largest dry-steam geothermal field—The Geysers reservoir, in California—led to a sharp decline in productivity when steam pressure dropped much faster than originally expected. Despite this decline, there has been a renewal of interest in the development of new geothermal plants in the western United States, driven by a variety of technological and economic trends. In particular, improvements in resource exploration, development, and monitoring will help avoid problems like those at The Geysers, and more-efficient energy conversion technology will help bring lower-temperature geothermal fields on-line.

A number of ocean-based technologies, including wave power and tidal power, are sparking interest as feasibility demonstration projects take shape in different parts of the world. Wave energy is less intermittent, easier to forecast, and has higher power per unit area than wind and solar energy, thus substantially easing concerns over the variability, predictability, and diffuseness of the resource.

These factors make wave-generated power not only more dispatchable but potentially low-cost as well. In May and August of 2004, two full-scale prototypes in Portugal and the United Kingdom provided the first electricity from offshore wave power plants to electrical grids. EPRI studies show that wave energy projects may be commercially viable at favorable sites in the United States, with the first installations likely to be sited in Hawaii, Oregon, or northern California.

Existing tidal power plants include a 240-MW plant in France, a 20-MW plant in Nova Scotia, and a 0.5-MW plant in Russia. These installations all use dams to impound the tidal waters before releasing them through generators to produce electricity like conventional hydroelectric plants. Tidal in-stream energy conversion (TISEC) harnesses the kinetic energy of water moving in a flowing tidal stream without the need for a dam or impoundment. A 300-kW experimental TISEC prototype has been in operation in the United Kingdom for over three years, and a 120-kW and two 1-MW demonstration projects are scheduled to begin testing this year in New York and the United Kingdom, respectively. EPRI studies show that TISEC projects may be commercially viable today at sites whose average annual power per unit area exceeds 3 kW/m^2. According to EPRI research, large-scale TISEC devices should be ready for pilot-scale demonstration in the United States and Canada within a year or two.

The Future for Renewables

Renewable energy has much going for it as part of a balanced power technology portfolio. It has strong public, political, and regulatory support, and it speaks directly to increasing concerns about global climate change and other environmental impacts of fossil fuel use. Renewable Portfolio Standards (RPS), mandating that a percentage of an entity's generation come from renewable energy sources, are expected to materially increase the amount of such sources employed. Approximately 20 states representing more than 52% of the U.S. retail electricity market have already adopted RPS programs, and more states are likely to follow. Partly as a result of such standards, it is expected that nearly 53,000 MW of new renewable capacity will be added in the United States by 2020. In Europe, the 25 EU member states have adopted the near-term target of a 21% "green electricity" market share.

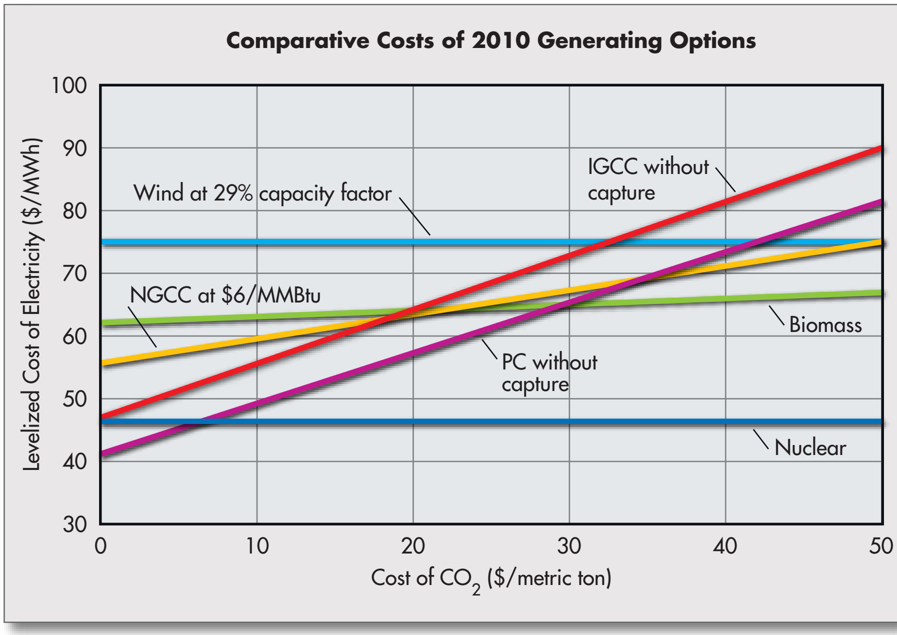
Still, despite strong global capacity growth—20–30% a year for wind and 40% for photovoltaics—it will take several decades for renewable energy to substantially increase its contributions to our energy supply. Of the 9% of U.S. electricity generation provided by renewables in 2004, over 8 percentage points came from hydroelectric and biomass energy; wind, geothermal, and solar technologies combined contributed less than 1% of the national total. Realizing the true promise of renewables will require sustained, concerted RD&D efforts: continued cost reduction, successful integration of technologies into the power grid, and utilization of renewable technologies in both centralized and distributed applications.

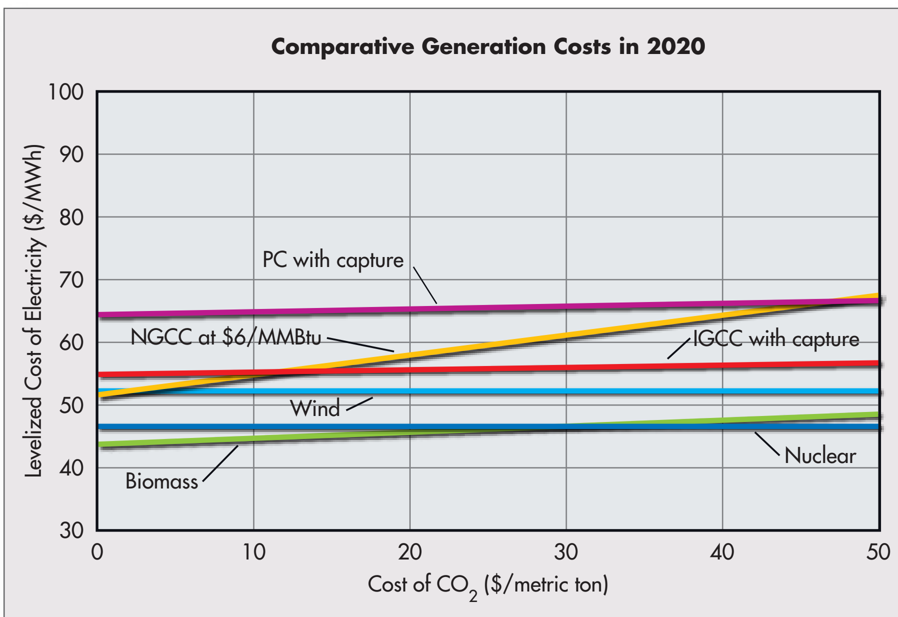
A ROBUST PORTFOLIO
OPTIONS FOR THE FUTURE

The United States must keep all of its major energy options open to meet the economic and environmental uncertainties of the future. For electricity, this means building and sustaining a robust portfolio of clean, affordable options, ensuring the continued use of coal, nuclear, gas, renewables, and end-use efficiency. Foreclosing any of these options in the first half of the twenty-first century could hobble efforts to achieve a sustainable energy future.

Investment decisions being made today about the next generation of electricity supply are complicated by four major uncertainties: the future cost of CO_2, the future price of natural gas, the storage of spent nuclear fuel, and the capture and storage of CO_2. As described earlier, prudent investment decisions for plants that have to produce electricity for the next 30 to 50 years will be increasingly based on the assumption that carbon constraints are coming. Whether decision makers assume the future cost of CO_2 to be zero (as it is today) or \$30/tCO_2 or \$50/tCO_2 will dramatically change the relative costs of the various supply options.

R&D can and will make a big difference, as shown in the two graphs that follow. By opening the possibility of capturing and sequestering CO_2 emissions from fossil fuels, the entire portfolio becomes relatively insensitive to the future cost of carbon constraints. Without advances in technology, as shown in the 2010 graph, the costs of electricity rise steeply for carbon-based technologies as CO_2 costs increase; but with successful R&D—shown in the 2020 graph—the cost curves are





flattened. Electricity generation costs for all options can be improved substantially over the next ten years, effectively putting the entire portfolio in the "affordable" range—below $70/MWh—regardless of CO_2 cost.

EPRI has taken an objective look across all the major electricity supply options, factoring in a range of possible CO_2 and natural gas costs and the technical progress that appears achievable over the next 10 years. The assessment strongly supports a powerful conclusion: the United States has an extraordinary opportunity to put a low-carbon generation portfolio in place by 2020. This means the technologies would be ready for deployment by 2015 and installed by 2020. The portfolio would be largely insensitive to the cost of CO_2 and yet still be affordable for much of the developed world and some parts of the developing world.

Developing such a low-carbon portfolio of generation options and expanding the potential for energy efficiency is critical for the future. Scenario research makes it clear that the tighter the limits on CO_2, the more electricity will be required globally. This derives from an undeniable reality—electricity is the *only* practical way to deliver clean energy on a large scale.

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